SECTION 5.0

WELL CONSTRUCTION

SASOL CHEMICALS (USA), LLC

2020 HWDIR PETITION EXEMPTION REISSUANCE REQUEST

SECTION 5.0 WELL CONSTRUCTION

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5.0 WELL CONSTRUCTION

The Sasol Chemical (USA), LLC, Greens Bayou Plant operates two Class I injection wells completed into sands of the lower Frio Formation. The following section describes the procedures used to drill, complete, and operate each of the active wells. A chronology of significant events (changes to well configuration(s)) is also included.

The Sasol Chemicals (USA), LLC Greens Bayou Plant Injection Wells have been constructed in accordance with United States Environmental Protection Agency (EPA) 40 CFR §146 and Texas Administrative Code (TAC) §331.62 standards for Class I Injection Wells.

5.1 PLANT WELL NO. 1 (WDW147)

All depths are referenced to the original kelly bushing (KB), which is 16 feet above ground level.

5.1.1 Drilling

Plant Well No. 1 (WDW147) was originally permitted by the Texas Water Commission (predecessor to the Texas Commission on Environmental Quality) on June 26, 1978, and drilling was started ("spudded") on August 8, 1978. The current underground injection control permit for Plant Well No. 1 (WDW147) is included in Appendix 5-1. The well was drilled to a total depth of 7,336 feet into the upper Vicksburg Formation. A 15-inch diameter bit was used to drill the surface casing hole to a depth of 2,728 feet, where the surface casing was set. A 9-7/8-inch hole was then drilled to a TD of 7,336 feet. Caliper, Induction/Electric, and Cement Bond Logs were run to determine the hole volume for cementing operations and to evaluate formation characteristics (see Appendix 5-2 for cement volume calculations). Completion activities were performed during June to August 1979, following construction of the surface facilities.

5.1.2 Well Design and Construction

Twenty-inch conductor casing was driven to 83 feet. Surface casing (10-3/4-inch, 40.5 lb/ft, K-55) was set at 2,727.61 feet and cemented to surface with 1,100 sacks of Lite-Wate cement containing 3 percent NaCl, and 600 sacks of Class H cement containing 10 percent NaCl. Cement was circulated to the surface in order to isolate and protect the shallow fresh water aquifers.

The 7-inch protection casing was set at 7,305 feet; it consists of 5,400 feet of 23 lb/ft K-55 casing and 2,005 feet of 26 lb/ft K-55 casing (with float collar and float shoe). Caliper and electric logs were run in the open-hole prior to completion to determine the volume of the hole and formation characteristics. Cementing of the 7-inch casing was accomplished with 520 sacks of Lite-Wate cement and 300 sacks of Class H cement containing 10 percent NaCl and 0.8 percent Halad 9. Centralizers were used to enable the cement to circulate completely around the casing. A cement bond log was run and the top of cement was interpreted to be present at 3,308 feet. The quality of the bond to the casing and formation indicates that the cement effectively isolates the injection interval sands within the Frio Formation Injection Zone. Plant Well No. 1 (WDW147) was originally completed on August 3, 1979, after being perforated in the lower Frio Formation from 6700 - 6780 feet (Frio E&F Sand Injection Interval).

A buffer program for Plant Well No. 1 (WDW147) was carried out from August 5 - 9, 1979, when the program was completed and the well put into service. The buffer program consisted of placing filtered Frio Formation water and calcium-free water ahead of the waste stream. The pH of the calcium-free brine was adjusted with caustic soda, and a clay stabilizer was added to the filtered water in the frac tanks before being injected.

The cement bond log indicates multiple areas of high-quality cement bond throughout this interval of interest, demonstrating that the protection casing cement serves as an excellent barrier to prevent upward flow of injected fluids from the Frio Injection Zone. In addition, historic temperature surveys have been conducted on the well since its installation. These temperature surveys have been conducted on the well while it is under static conditions and have demonstrated the absence of fluid movement either out of the permitted Injection Zone or along the borehole of Plant Well No. 1 (WDW147). Therefore, the Greens Bayou Plant asserts that the current construction of Plant Well No. 1 (WDW147) is adequate to prevent contamination of the lowermost USDW by injected fluids from the site or inter-formational flow.

5.1.3 Original Completion

The lower Frio sands (Frio E&F Sand Injection Interval) were perforated on several runs from 6,700 feet to 6,780 feet.

5.1.4 Current Completion

The current completion consists of casing perforations into the Frio E&F Sand from 6,620-6,680 feet and 6,700-6,780 feet, respectively. Fill was tagged at 6,720 feet. The injection well string in the well consists of 6,476 feet of 4-1/2-inch, 11.6 Lb/ft, L-80 tubing set into a Baker model FB-1 Retainer Production Packer at 6,486 feet. The burst pressure of the tubing is 7,780 psi, the collapse pressure is 6,350 psi, and the tensile strength of the tubing is 212,000 pounds. Tubing calculations are contained in Appendix 5-4. The tubing/casing annulus is filled with 9.9 lb/gal brine with corrosion inhibitors and bactericides, and HEC polymer. The current well configuration, including casing and cementing information, is shown in Figure 5-1.

5.1.5 Well History – Plant Well No. 1

The well has been used for the disposal of process wastewaters at the Greens Bayou Plant since August 1979. Annual mechanical integrity tests are conducted in the well and injection sand to remain in compliance with regulatory requirements. The well has been mechanically worked over only once since its initial completion. The workover added perforations to the original completion in the Frio E&F Sand Injection Interval. No other mechanical changes were made to the well. The well workover history since the construction of the well is presented below:

<u>March 29-30, 1983</u>

An acid and nitrogen-jetting job was performed to lower the surface injection pressure. The acid job consisted of 80 bbls of 10-lb/gal low-calcium brine followed by 500 gals of 15 percent HCl containing corrosion inhibitor. The acid was displaced to the perforations with 110 bbls of brine and allowed to soak for four hours. The nitrogen jetting removed 1,400 bbls of fluid and solids. Prior to returning the well to injection operations, 280 bbls of low-calcium brine, containing one percent by volume Halliburton Cla-Sta II, was injected, followed by 190 bbls of similar brine with an adjusted pH of 9.5.

July 29-31, 1986

The 7-inch casing was perforated from 6,620 – 6,680 feet (Frio E&F Sand Injection Interval) with four shots per foot and acidized with 10,000 gallons of 7-1/2 percent HCL and 8,000 gallons of 12-3 percent HCL - HF acid. A bottomhole pressure survey recorded a static pressure of 2,904 psi at 6,700 feet Kelly bushing (KB) over a two hour time period. The indicated static fluid level was 1,150 feet below ground. The bottom-hole temperature was 132 °F at 6,700 feet, and the gradient was 0.433 psi/ft. A radioactive tracer log was run and no evidence of vertical migration behind casing was discovered. The annulus pressure test was run with plant pumps. The test was started with 895 psi on the annulus and the well not injecting. Injection began at 60 gpm. Final annulus pressure was recorded to be 985 psi after 30 minutes.

September 2000 to January 2002

Plant Well No. 1 (WDW147) started experiencing a small volume annular leak in April 2000, however, the well was able to maintain the required minimum 100 psi pressure differential. In September 2000, Sasol began adding a viscosity modifier to the annulus fluid in the well. The viscosity modifier is a noncorrosive, environmentally responsible hydroxyethylcellulose (HEC), mixed with glutaraldehyde (Aldacide G) solution. To this date, approximately 4,900 gallons of HEC had been added to the well. The well successfully passed annual mechanical integrity tests in since 2001.

October – November 2010

Plant Well No. 1 (WDW147) started experiencing a small volume annular leak in April 2000, however, the well was able to maintain the required minimum 100 psi pressure differential. In September 2000, Sasol began adding a viscosity modifier to the annulus fluid in the well. The viscosity modifier is a noncorrosive, environmentally responsible hydroxyethylcellulose (HEC), mixed with glutaraldehyde (Aldacide G) solution. The well was on active/standby status since the start-up and operation on Plant Well No. 2 (WDW319). The well has passed annual mechanical integrity testing each year from 2001 through 2009.

Key Energy (Key) mobilized Rig No. 1550 to the Greens Bayou Plant on October 18, 2010. The derrick was raised, and all equipment was rigged up to Plant Well No. 1 (WDW147). On October 19, 2010, the wellbore was flushed with 125 barrels of 8.75 pound per gallon (ppg) sodium chloride brine, and the wellhead tree was removed. A 7-1/16-inch, 5000M double ram blow out preventer (BOP) was installed on the tubing spool.

Frank's Casing (power tongs) and Weatherford (casing spear) personnel and equipment were mobilized to the site on October 20, 2010. The tongs were rigged up, and a casing spear was dressed with a 3.875-inch outside diameter (OD) grapple and attached to a 2-7/8-inch pup joint (10 feet in length). The spear was engaged in the 3.875-inch reduced inside diameter (ID) of the tubing hanger, and an overpull was applied to the spear to verify setting. Tension (70,000 pounds hookload, 5,000 pounds over string weight) was applied and then increased to 80,000 pounds without moving the hanger. The hanger was ultimately pulled free after increasing the annulus pressure to 550 psi and working the spear from 60,000 to 120,000 pounds. The seal assembly was pulled out of the packer with drag of 10,000 to 20,000 pounds, and the tubing hanger was laid down. A total of 200 joints of 4-1/2-inch OD, 11.6 pounds per foot (ppf), K-55, STC (range II and III) casing, 4-1/2-inch seating nipple, 1 joint of 4-1/2-inch, 11.6 ppf, K-55, STC casing, crossover, and the Baker seal assembly with 11 seal units were removed from the well. The Baker seal assembly was shipped to Baker Oil Tools in Beaumont for inspection.

The casing was scraped, and a 40-Arm Sondex caliper tool was run from 6,486 feet to 10 feet at an average logging speed of 40 feet per minute. The Sondex was lowered back into the wellbore, and repeat sections were run on the following intervals: 5455 to 5,300 feet; 4,955 to 4,850 feet; 3,016 to 2,948 feet; and 1,694 to 1,620 feet.

A series of pressure tests were conducted to verify the integrity of the 7-inch protection casing. The testing confirmed the mechanical integrity of the 7-inch casing from 4,087 feet to surface, however, a casing leak was indicated between 4,087 feet and 4,097 feet. A bottomhole assembly (BHA), consisting of a 6-1/4-inch OD tapered mill, 6-1/4-inch OD string mill, 7-inch casing scraper, 6-1/4-inch watermelon/string mill, and bit sub, was made up and lowered into the wellbore on the 2-7/8-inch workstring. The BHA was worked up and down over the interval from 4,046 feet to 4,148 feet multiple times to prepare the damaged interval of the 7-inch casing for the installation of a casing patch.

Prior to setting the patch, a Baker Model FB-1 80-40 production packer with a 10-foot long 80-40 sealbore extension (4-inch ID), 2 crossovers, and the 4.24-foot long redressed 80-40 seal assembly (4-inch OD) was made up and lowered into the wellbore. The redressed 80-40 seal assembly was landed in the original Baker packer with the seals positioned from 6,489 feet to 6,486 feet. The setting ball was dropped through the workstring. Hydraulic pressure (2,000 psi) was applied to set the FB-1 packer (top of the packer element at 6,473.6 feet, top of packer at 6,472.3 feet). The packer set was confirmed by pulling tension of 43,000 pounds.

Operations commenced on November 2, 2010, to install the 40-foot long Weatherford 7-inch, 23 (ppf) HOMCO casing patch. The casing patch was prepared for installation with the application of the two part epoxy applied to the exterior of the patch. The casing patch and setting equipment were lowered into the wellbore on the 2-7/8-inch workstring and positioned with the bottom at 4,113 feet and top of patch at 4,073 feet. The casing patch was set by hydraulically stroking the setting collet through the patch in a series of 12 cycles until the collet was pulled out of the top of the patch. The hydraulic setting pressure to stroke the setting tool ranged from 900 psi to 1,200 psi during the installation.

A series of pressure tests were conducted on November 3, 2010, after installation of the casing patch. A seal assembly with 2 seal stacks was lowered into the wellbore on the 2-7/8-inch workstring, and the seals were landed in the FB-1 packer sealbore. The pressure testing did not meet the test requirements of less than 5 percent pressure loss in 30 minutes. Weatherford personnel and equipment were mobilized back to the site on November 5, 2010, and the casing patch setting equipment (collet and cone for 7-inch, 23 ppf casing) was lowered into the wellbore and pushed through the casing patch with 4,000 pounds. The cone and collet were worked through the casing numerous times with an overpull of approximately 4,000 to 10,000 pounds over the length of the patch. A single tight spot over the center of the patch required an overpull of approximately 10,000 to 12,000 pounds on each pass.

The cone and collet were replaced with a cone and collet for 7-inch 20 ppf casing, the next larger collet. This assembly was worked through the casing patch 8 times to further expand the casing patch. The equipment was rigged down, and a series of unsuccessful annulus pressure tests were conducted from November 6 to November 8, 2010, with the seal assembly landed in FB-1 packer sealbore and from November 6 to November 14, 2010, using an inflatable packer. The testing confirmed an additional leak in the 7-inch casing in the interval from 5,126 feet to 5,141 feet.

An inflatable bridge plug was picked up and lowered into the wellbore and set at 5,187 feet. SealMaker's eight stage squeeze treatment (1,200 gallons) was circulated into the wellbore through the 2-7/8-inch workstring at 5,120 feet. The treatment was squeezed into the damaged casing by pressurizing the workstring and casing annulus to 1,675 psi and 1,820 psi, respectively. The pressure bleed off was recorded. A positive annulus pressure differential of approximately 150 psi over the workstring pressure was maintained. A nitrogen system was installed to continue the maintenance of the pressure differential. The squeeze pressure was maintained for approximately 17 hours. Pressure was bled off the workstring and annulus, and the excess squeeze treatment chemicals were reverse circulated out of the wellbore. The 7-inch casing from 5,187 feet to the surface was successfully pressure tested with an initial test pressure of 1,342 psia. The final test pressure was 1,332 psia after 60 minutes. The pressure was bled off, and the bridge plug was removed from the wellbore and returned to Baker.

The seal assembly was lowered into the wellbore and landed in the completion packer sealbore from 6,181 feet to 6,183 feet. The annulus from the completion packer to the surface was successfully pressure tested with an initial pressure of 1,302.8 psia on November 17, 2010. The final test pressure after 30 minutes was 1,300.1 psia for a 0.2 percent loss rate during the test.

Tubing running equipment was rigged up for the installation of the injection tubing, and the

4-1/2-inch injection tubing was run into the well. The string consisted of the Baker 4-inch seal assembly, 3-1/2-inch EUE pin x 4-1/2-inch LTC box crossover, one 4-1/2-inch, L-80, LTC pup joint (4.25 feet), and 147 full joints of 4-1/2-inch, 11.6 ppf, L-80 LTC casing. Each connection was made up to the optimum torque (2,230 foot-pounds) and externally pressure tested to 3,000 psi. The seal assembly tagged the top of the new completion packer at 6,473.5 feet, and the space out was determined. A total of 120 barrels of 9.0 ppg brine mixed with 1% Cortron was pumped into the tubing-casing annulus. A 4-1/2-inch, 11.6 ppf, L-80, LTC pup joint (2.15 feet) and tubing hanger with a 4-1/2-inch, 11.6 ppf, P-110, LTC double pin sub were made up and externally pressure tested. The tubing hanger was landed with approximately 12,000 pounds of weight set down on the seal assembly No-Go. Pressure testing of the annulus was conducted on November 22 and November 23, 2010, however, an acceptable test was not obtained. A decision was made to reperform the SealMaker squeeze treatment, however, this time the treatment was run through the tubing-casing annulus.

A 65 gallon batch of high density (13.9 lb/gal) SealMaker annulus treatment (50 gallons of EnviroPlug, 5 gallons of SealMaker, and 10 gallons of Vortex B) was mixed and spotted in the annulus on November 25, 2010. Squeeze pressure was maintained on the annulus while the high density annulus treatment migrated through the annulus brine. The annulus pressure was increased to approximately 1,700 psia, allowed to bleed down to approximately 1,300 psia, and increased back up to approximately 1,700 psia. The pressurization and bleed off cycles were repeated regularly for approximately 20 hours.

A successful preliminary annulus pressure test was performed on November 27, 2010. The testing procedure followed mechanical integrity testing guidelines, with a pressure decrease of 2.4% percent recorded over the 30-minute test period. Following the successful pressure test, the workover rig and all ancillary equipment were moved off the location and returned to the Key Energy yard. A mechanical integrity test was successfully performed on the well on December 5, 2010, and the well remains in stand-by injection service.

5.2 PLANT WELL NO. 2 (WDW319)

All depths are referenced to the original KB, which is 19.5 feet above ground level.

5.2.1 Drilling

Plant Well No. 2 (WDW319) was originally permitted by the Texas Natural Resource Conservation Commission July 21, 1995. The well was spudded on July 26, 2000, with conductor casing being set, and drilling operations commenced on August 7, 2000. The well was drilled to a total depth of 7,408 feet into the Frio Formation. A 17-1/2-inch diameter bit was used to drill a hole to 3,300 feet, where surface casing (13-3/8-inch) was set and cemented to surface. A 12-1/4-inch hole was then drilled to total depth. Drilling was completed in September 2000.

5.2.2 Well Design and Construction

Twenty-inch conductor casing was driven to 81 feet. Surface casing (13-3/8-inch, 61 lb/ft, J-55) was set at 3,300 feet and cemented to surface with: 2,543 sacks of 15 percent Poz and 85 percent Class H cement, containing 8 percent gel, 5 percent salt, 0.25 lb/sack Cello flake, 0.5 percent FL-52, 7.45 percent gilsonite, 0.2 percent SM, and 0.005 gal/sack FP-6L (first slurry); and 674 sacks of Class H cement containing 0.25 lb/sack Cello flake, and 0.005 gal/sack FP-6L (second slurry). Cement was circulated to the surface in order to isolate and protect the shallow fresh water aquifers.

The 9-5/8-inch protection casing (N-80, 47 lb/ft) was set at 7,352 feet. Initial cementing (first stage) of the 9-5/8-inch casing was accomplished with 1,088 sacks of Class H cement with 2 percent CD-32, 0.1 percent R-3, and 0.005 gal/sack FP-6L. A wiper plug was pumped using 9.6 lb/gal PHPA polymer mud as a displacement fluid. The first stage wiper plug was landed in the float collar and a pressure of 2,200 psi was applied. The cement stage opening device was dropped and allowed to free fall. A pressure of 900 psi was applied to the cement stage tool opening device; the tool opened. The wellbore was circulated for approximately four hours with returns to surface. The first slurry of the second stage consisted of 846 sacks of Class A cement containing 3 percent salt, 0.2 percent R-3, 0.25 lb/sack Cello flake, 4 percent SM, and 0.005 gal/sack FP-6L. The second slurry consisted of 533 sacks of Class H cement with 2 percent gel, 0.1 percent CD-32, 10 percent salt, and 0.005 gal/sack FP-6L. However, pump pressures increased during pumping of the second slurry, close to the cement setting. The cement pumping was stopped before completing the displacement. Cement was drilled and washed down to the cement stage tool closing sleeve. The sleeve was closed with weight on the bit and then the cement stage tool opening device was drilled out. The drill string was lowered to the float collar, tagging cement at 7,187 feet. Cement was drilled to a depth of 7,307 feet.

The 9-5/8-inch casing was hydraulically cut and pulled from a depth of 3,661 feet. Cement was reamed from the wellbore and from behind the top of the severed casing at 3,661 feet to a depth of 3,667 feet using a washover shoe. A Bowen 11-1/8-inch by 9-5/8-inch external casing patch with grapple and seal was screwed into a Weatherford 9-5/8-inch cement stage tool and run on the re-threaded 9-5/8-inch casing. The external casing patch was lowered over the top of the 9-5/8-inch casing, at a depth of 3,661 feet and an upward pull of 40,000 lbs over string weight was used to set the grapple and seal. A cement tool opening device was dropped in the well and allowed to free fall. A pressure of 1,750 psi was applied to the cement stage tool opening device, and the tool opened as designed. Drilling mud (9.4 lb/gal) was circulated for 90 minutes. The lead cement slurry consisted of 550 sacks of Class A cement with 35 percent Poz, 8 percent gel, 5 percent salt, and 3 percent R-3. The tail slurry consisted of 250 sacks of Class H cement with 2 percent gel, 10 percent salt, and 0.1 percent CD-32. Cement was observed in the annular area when the blow out preventers were lifted to set the casing slips. After allowing the cement to cure, drilling tools were lowered in the well, and the cement stage tool was drilled out.

Centralizers were used to enable the cement to circulate completely around the casing. A cement bond log was run, and the top of cement was interpreted to be present to surface. The quality of the bond to the casing and formation indicates that the cement effectively isolates the Injection Interval within the Injection Zone.

The cement bond log indicates the protection casing is fully cemented in this interval, with no voids or areas of poor cement indicated. The protection casing cement serves as an excellent barrier to upward flow of injected fluids from the injection zone. In addition, numerous temperature surveys conducted on the well since its installation have demonstrated the absence of fluid movement along the borehole of Plant Well No. 2 (WDW319). Therefore, the Greens Bayou Plant asserts that the current construction of Plant Well No. 2 (WDW319) is adequate to prevent contamination of the lowermost USDW by injected fluids from the site or inter-formational flow.

Plant Well No. 2 (WDW319) was perforated on September 14, 2000, in the lower Frio Formation from 6,850 – 7,260 feet (Frio A/B/C Sand Interval). The hole was washed and circulated to 7,312 feet, and 15 percent HCl was balanced and squeezed through the perforations (approximately 42 gal/ft). Spent acid was jetted from the well with coiled tubing and nitrogen (approximately 2,700 barrels returned to surface). A Baker Model 192 FA 73 permanent packer was set at 6,498 feet and 7-inch injection tubing with seal assembly was landed in the packer. Mechanical integrity testing (annulus pressure test, radioactive tracer log, and temperature log) were conducted from September 22 to 27, 2000. These tests confirmed the initial integrity of the well. The well was placed in service on December 27, 2000.

5.2.3 Original Completion

The sands in the comingled Frio A/B/C Sand Injection Interval were perforated with a w/5 shots per foot on several runs as follows: Frio A/B Sand – 6,850 to 6,865 feet, 6,888 to 6,903 feet, 6,920 to 6,935 feet, and 6,954 to 6,974 feet; and Frio C Sand – 7,114 to 7,144 feet, 7,216 to 7,236 feet, and 7,240 to 7,260 feet.

5.2.4 Current Completion

Plant Well No. 2 (WDW319) is perforated in the commingled Frio A/B/C Sand Injection Interval from 6,850 to 7,260 feet. The injection well string in the well consists of 6,497 feet of 7-inch, 26.0 Lb/ft, P-110 LT&C tubing set into a Baker model FA Packer at 6,498 feet. The burst pressure of the tubing is 9,960 psi, the collapse pressure is 6,230 psi, and the tensile strength of the tubing is 693,000 pounds. Tubing calculations are contained in Appendix 5-4. The tubing/casing annulus is filled with 10.0 lb/gal brine with corrosion inhibitors. The current well configuration, including casing and cementing information, is shown in Figure 5-2 and Table 5-3.

5.2.5 Well History - Plant Well No. 2

The well has been used for the disposal of process wastewaters at the Greens Bayou Plant since December 2000. Annual mechanical integrity tests are conducted in the well and injection sand to remain in compliance with regulatory requirements.

<u>March 2001</u>

A slickline unit was rigged up, and a drive-down bailer was run in the well. Fill was tagged at 7,269.5 feet. The bailer engaged, and a small volume of solids was retrieved. Halliburton analyzed the sample and determined that the material was predominately calcium carbonate sludge with a small amount of iron oxide. Plant Well No. 2 (WDW319) was acidized by bullheading 15 percent HCl followed by flushes of Cla-Sta II (165 gallons of Clay-Sta II mixed with low calcium magnesium brine) and low calcium magnesium brine. The well went on vacuum when the acid reached the perforations.

Plant Well No. 2 (WDW319) was treated with 6,000 gallons of NaOH in an attempt to decrease injection pressure. No improvement was observed. The wellbore was then displaced with 275 barrels of low calcium magnesium brine. Coiled tubing was run in the well and positioned at 7,260 feet. The well was stimulated by reciprocating the coiled tubing across the perforations (7,260 to 6,850 feet) with 6,500 gallons of inhibited 15 percent HCl. The wellbore was displaced with 65 barrels of low calcium magnesium brine. Injectivity of the well was increased three-fold (from 0.31 gpm/psi to 0.93 gpm/psi).

<u>May 7 to 14, 2001</u>

A workover rig and associated equipment was moved in and rigged up. Blow out preventers were rigged up and a 2-7/8-inch workstring was run in the well. Fill was tagged at 6,929 feet. The well was circulated with 4 percent KCl (lost 200 barrels of 300 barrels pumped). The well was reverse circulated and fill was removed from the well to a depth of 7,253 feet, where circulation was lost. A total of 900 barrels of 4 percent KCl were pumped into the well to flush the perforations. The workstring was positioned at 7,192 feet and the following treatment was pumped: 20 barrels of 10 lb/gal NaCl brine preflush; 3,500 gallons of 15 percent HCl with corrosion inhibitor and iron sequestering agent; followed by a post-flush of 100 barrels of 10 lb/gal NaCl brine. The workstring was pulled from the well. After reassembling the wellhead, a bullhead acid stimulation was performed as follows: pumped 20 barrels of 10 lb/gal NaCl brine preflush; 3,000 gallons of 15 percent HCl with corrosion inhibitor and iron sequestering agent; followed by a post-flush of 350 barrels of 10 lb/gal NaCl brine. The well went on vacuum during pumping of the post-flush brine. A spinner/temperature survey was conducted after tagging fill in the well at 7,214 feet. The spinner survey/temperature survey included dynamic and stationary stops with an injection rate of 4 to 4.5 barrels per minute. Data indicated that the Frio C Sand was not taking flow.

March 2002

Remedial Well Cleanout and Stimulation operations were conducted on Plant Well No. 2 (WDW319) to improve the flow distribution of injected fluids and to reduce the amount of near-wellbore formation damage (skin). Remedial operations were conducted during the period of March 4 to 7, 2002.

On the morning of March 4, 2002, Sasol ceased wastewater injection into the well. Five 500-barrel frac tanks were spotted on location to store workover and test fluids, and a vacuum box was set up to handle fluid returns. Moncla Rig No. 48 was mobilized to the site, and the rig and ancillary equipment were rigged up. The wastewater in the injection tubing was purged from the wellbore using 500 barrels (bbl) of 8.7 pound per gallon (lb/gal) sodium chloride (NaCl) brine, followed by 350 bbl of 3% potassium chloride (KCl) brine substitute (3% KCl fluid).

After ensuring the well was on vacuum, the wellhead was removed, and well control equipment was installed. Rig-up of the well servicing unit was completed, and a 4-1/2-inch outside diameter (OD) bit and workstring (2-7/8-inch OD) were picked up. The bit was lowered in the wellbore to 6,507 feet workstring measurement (WM), where it tagged up on an obstruction. Efforts to get past the obstruction were unsuccessful, and the bit was retrieved from the wellbore. A muleshoe sub was attached to the end of the workstring, for use in washing out solids fill from the wellbore.

The muleshoe was lowered in the wellbore to the top of solids fill, which was located at 7,194 feet. A power swivel was then picked up, and a stripper head was installed above the well control equipment to enable circulation of the wellbore. Solids fill, primarily comprised of formation sand, was washed from the wellbore down to 7,314 feet WM, where plug back total depth (PBTD) was encountered. The well was circulated thoroughly to remove solids in the workover fluid, and the end of the muleshoe was pulled up to approximately 6,788 feet WM. The well was allowed to stabilize, and the muleshoe was lowered to bottom. No fill was located above PBTD, and the wellbore was then displaced (bullhead technique) with 300 bbl of clean 3% KCl fluid, followed by 60 bbl of 8.7 lb/gal NaCl brine.

The muleshoe was pulled up to 6,819 feet, and Hub City's acid pumping equipment was rigged up and pressure-tested. An 11,000-gallon acid stimulation treatment was then pumped in five stages, using 15% HCl and 12%-3% HCl/HF acid. The stimulation treatment was pumped at two to four bpm injection rate, with surface injection pressures ranging from 150 to 480 pounds per square inch gauge (psig). Benzoic acid flakes were used as diverter. Following acid treatment, 1,000 gallons of methanol was pumped to dissolve the benzoic acid flakes, and the well was flushed with 300 bbl of 3% KCl fluid.

The wellbore was displaced (bullheaded) with 300 bbl of 10 lb/gal NaCl brine, and the work string was retrieved from the wellbore (laying down joints) while pumping brine into the annulus to prevent sand surging and intrusion into the wellbore. The well control equipment was removed, and the upper section of wellhead was reassembled. The rig tank was cleaned, and the well servicing unit was rigged down and de-mobilized from the well.

July 2004

Remedial Cleanout and Stimulation operations were conducted on Plant Well No. 2 (WDW319) to improve the injection efficiency of the well and to reduce the amount of near-wellbore formation damage (skin). Remedial operations were conducted during the period of July 26 to 29, 2004.

On the morning of July 26, 2004, Sasol ceased wastewater injection into the well. Five 500-barrel frac tanks were spotted on location to store workover and test fluids, and two vacuum boxes were set up to handle fluid returns. Moncla Rig No. 9 was mobilized to the site, and the rig and ancillary equipment were rigged up. On the following day, wastewater in the injection tubing was purged from the wellbore using 500 bbl of 8.7 lb/gal sodium chloride (NaCl) brine, followed by 350 bbl of 3% potassium chloride (KCl) brine substitute (3% KCl fluid).

After ensuring the well was on vacuum, the wellhead was removed, and well control equipment was installed. Rig-up of the well servicing unit was completed, and a 4-1/2-inch OD bit and workstring (2-7/8-inch OD) were picked up. A muleshoe sub was attached to the end of the workstring for use in washing out solids fill from the wellbore. The muleshoe was lowered in the wellbore to the top of solids fill, which was located at 7,205 feet. Solids fill, primarily comprised of formation sand, was washed from the wellbore down to 7,320 feet, where PBTD was encountered.

On July 28, the well was circulated thoroughly to remove solids in the workover fluid, and the end of the muleshoe was pulled up to approximately 6,800 feet. Hub City's acid pumping equipment was rigged up and pressure-tested. An 11,000-gallon acid stimulation treatment was then pumped in five stages, using 15% HCl and 7-1/2%-1-1/2% HCl/HF acid. The stimulation treatment was pumped at 2-1/2 bpm injection rate, with surface injection pressures ranging from 0 to 114 psig. Benzoic acid flakes were used as diverter. Following acid treatment, 1,000 gallons of methanol was pumped to dissolve the benzoic acid flakes, and the well was flushed with 300 bbl of 3% KCl fluid.

Mechanical integrity of Plant Well No. 2 (WDW319) was demonstrated by running an annulus pressure test and a radioactive tracer survey on July 30, 2004. The annular pressure was increased to 1,062.49 psig and showed a 20.1 psi pressure increase over a thirty minute period. A complete radioactive tracer survey was run, demonstrating packer, casing, and cement integrity. Bottomhole pressure of 2,980.22 psia was measured at 6,850 feet with a bottomhole measured temperature of 115.34 °F.

July 31 –August 3, 2007

A wellbore cleanout and acid stimulation treatment were conducted. A well servicing unit and small diameter workstring was used to circulate out solids from the wellbore. Solids were removed from 7,204 feet to 7,314 feet (well bottom). A multi-stage acid stimulation treatment was then pumped through the workstring to improve the well's injection performance. The acid stimulation treatment significantly lowered the well's injection pressure and improved the flow distribution into each of the permitted injection intervals

5.3 WELL MATERIALS COMPATIBILITY

5.3.1 Corrosion Introduction

To protect USDWs, injection wells must not allow fluids to escape into unauthorized zones. Any escape of fluids may cause contamination of a USDW, directly or indirectly, by forcing lower-quality fluids to move into these zones. If a well protects the USDW by not allowing fluids to escape or migrate, it is said to have mechanical integrity. The well materials must also be compatible with annular fluids, formation fluids, soil, and other elements of the well's environment. Sasol Chemicals (USA), LLC evaluated and performed well materials compatibility during original permitting and installation of the injection wells.

Most injection wells are constructed with metallic materials for structural reasons. Non-metallic materials may be used in specific areas where metals are not adequate. Corrosion of the metallic materials and/or degradation of the non-metallic materials are the chief causes of premature failure in injection wells.

5.3.2 Types of Corrosion

Corrosion can be defined as the destruction of metal by chemical or electrochemical reaction with its environment (Larrabee, 1946). At the corroding metal surface, two types of reactions occur simultaneously: anodic reaction, in which metal atoms are dissolved to form positively-charged ions and electrons (corrosion); and cathodic reaction, where specific ions in the electrolyte (fluids such as acids, alkalis, and salt solutions) accept the electrons.

Although there are several types of corrosion, they may be grouped into two main forms, general and localized. General corrosion is the uniform or near uniform thinning of metal. The corrosive environment penetrates the passive film over the entire surface area of the metal and the anodic and cathodic sites on the metal surface switch continuously, resulting in a relatively uniform metal loss. If the rate of general corrosion is tolerable, an adequate life span can be built into the well construction materials by adding a corrosion allowance to the design thickness. If the general corrosion rate is too high, the material should not be used.

Localized corrosion consists of several forms of attack (pitting and crevice corrosion) that can lead to failure of the equipment before the designed corrosion allowance is used up. The corrosive environment penetrates the passive film at only a few points, making them anodic in nature. This causes the rate of corrosion to be greater in some areas than others. Failure may arise from the development of a leak, from mechanical failure caused by localized thinning, or from crack formation and propagation.

Another form of corrosion that may be important in injection wells is galvanic corrosion. This occurs when two electrically dissimilar metals are in contact with one another in an electrolytic solution. The more active metal will be anodic to the other and will give up metal to the solution.

When non-metallic materials are exposed to a hostile environment, they may degrade. This type of degradation is generally physiochemical rather than electrochemical in nature (Perry, 1973). The degradation of non-metallic materials may exhibit a variety of forms: blistering, crazing, swelling, softening, and delamination. All degradation leads to the loss of structural properties and possible failure. One method of checking the applicability of non-metallic materials is to remove samples at regular intervals during exposure and to measure the loss of mechanical properties, such as flexural strength. If the loss is limited to an acceptable value, the material is usually considered suitable.

5.3.3 Factors Influencing Corrosiveness of Injection Well Environments

The potential for an injection well to experience corrosion depends on the materials of construction, the nature of the hydrologic and geologic environments, and the operating conditions.

Temperature and flow velocities can have a pronounced effect on corrosion. Increasing the temperature usually increases the corrosion rate (generally doubling for each additional 18°F), as does increased flow velocities. For example, concentrated sulfuric acid is not corrosive to carbon steel at ambient temperatures because it is strongly oxidizing, therefore, causing passivation (the formation of a protective film). However, if the temperature is raised or the velocity of flow is increased, concentrated sulfuric acid becomes extremely corrosive to carbon steel since the increased temperatures cause the protective film to dissolve, and the increased velocities cause the protective film to be mechanically removed. Increasing temperature also increases the opportunity for the occurrence of localized corrosion, such as pitting or stress corrosion cracking. Alloys which easily passivate, such as stainless steels and titanium, act in an opposite manner to carbon steel, and have better corrosion resistance under aerated (containing dissolved oxygen) or flowing conditions. They are more likely to be attacked when oxygen concentration is low, as in places of fluid stagnation such as joints or cracks.

The presence of aggressive species will alter corrosion behavior. The chloride ions, for example, may easily penetrate the passive film on stainless steel and cause deep localized pitting. Also, the presence of dissolved gases such as oxygen, carbon dioxide, hydrogen sulfide, and methane in fluids increase corrosion rates.

Since the discharge of hydrogen ions takes place in most corrosion reactions, the hydrogen ion concentration (pH) is a useful indicator of corrosiveness for certain alloy systems. Acidic (low pH) solutions are, as a general rule, more corrosive than neutral (pH 7), or alkaline (high pH) solutions. In the case of ordinary iron and steel, the dividing line between rapid corrosion in acid solutions and moderate or slow corrosion in nearly neutral or alkaline solutions occurs at a pH of about 4.5. With atmospheric metals, such as aluminum and zinc, highly alkaline (high pH) solutions may be more corrosive than acid solutions.

The synergistic effect of corrosive mixtures must also be considered. Combinations of chemicals, which by themselves are relatively non-corrosive, may be extremely aggressive towards specific alloys. For example, injection streams containing dilute nitric acid or dilute flowing sodium chloride are usually not corrosive towards stainless steel. However, if the two streams are combined, severe pitting of stainless steel may result.

To summarize, a variety of factors will affect the corrosiveness of an injection well environment. These include the characteristics of the alloy, the presence of aggressive species, the pH, the temperature, and velocity or turbulence of the flowing streams. It is also important to know whether chemical combinations present in the injection stream increase or decrease corrosion.

5.3.4 Corrosion Detection and Measurement

Tubing and casing materials should be compatible with the injection operation, as well as the fluids to be injected, and the environment in which the well is constructed. To determine proper construction materials, it may be desirable to test the corrosiveness of the injection fluid in the laboratory. Despite the consideration given to corrosion control during well design, there is often a need to recognize corrosive environments during well construction and to detect and measure corrosion during injection operations. Before initiating a corrosion-prevention program, it is necessary to determine if corrosion will occur, the cause of corrosion, and the rate and severity of corrosion. To determine the effectiveness of a corrosion-prevention program, the rate and effects of corrosion should be measured before and after application of preventative measures.

There are five commonly used methods to detect and measure corrosion. Methods include the use of corrosion loops, which are smaller-diameter pipes installed parallel to the injection tubing, which may be valved off and removed for inspection. Electrical resistance probes that measure changes in the resistance of a metal as it corrodes, polarization resistance probes, caliper surveys, and other well logging methods may also be used for corrosion detection and measurement.

At the Greens Bayou Plant, corrosion test racks are currently installed in the injection well piping leading to each of the injection wells, downstream of the injection pumps. The test metallurgies are consistent with the materials of construction. Under provisions set by the TCEQ permit, Sasol performs quarterly corrosion analysis. Results of the corrosion analyses are submitted to TCEQ with the quarterly injection reports.

Methods include the use of corrosion loops, which are smaller-diameter pipes installed parallel to the injection tubing, which may be valved off and removed for inspection. Electrical resistance probes that measure changes in the resistance of a metal as it corrodes, polarization resistance probes, caliper surveys, and other well logging methods may also be used for corrosion detection and measurement.

5.3.5 Corrosion Control

Corrosion can be minimized by the application of a number of different design considerations and operating techniques. The use of construction materials known to be resistant to the potentially corrosive environment is effective (Driscoll, 1986). The corrosive environment as well as the physical requirements of the system effect the choice of metals. Carbon steels are resistant to sulfide cracking, while stainless steel alloys or titanium are more suitable to acidic environments.

Altering the environment can make appreciable differences in the corrosion of metals. Changes in the oxygen concentration, temperature, velocity, and pH of the injection or annular fluids can help reduce corrosion.

The application of nonmetallic corrosion-resistant materials to well construction are limited to certain types of plastics. Other nonmetallic materials do not possess the characteristics necessary for injection tubing. The most extensively used nonmetallic tubular goods are constructed from fiberglass reinforced with epoxy resins. The material is highly resistant to corrosive fluids. It also affords good resistance to attack by corrosive acids and alkalis, although it has a relatively poor resistance to attack by organic solvents and dissolved chlorine. PVC and other plastic pipe also offer this corrosion-resistant capability but have lower strength and temperature ratings.

Protective coatings that separate the tubing from the corrosive environment, and cathodic protection (connecting a metal lower in the galvanic series electrically to the metal to be protected) are other corrosion-prevention measures. Operational measures such as degasification and/or neutralization of the injection stream, or the addition of corrosion inhibitors and bactericides also protect the construction materials from corrosion.

5.3.6 Corrosion and Hazardous Injection Fluids

EPA has recently conducted an inventory of Class I hazardous waste wells in the United States. The data collected provides a “data base” for determining the composition of the most generally injected waste fluids. Table 5-5 lists the most commonly injected fluids, as well as a description of the type of corrosion that can be caused by those fluids (EPA, 1987). For most Class I injection wells, pH neutralizers, cathodic, and protective coatings are probably the most effective methods for preventing corrosion.

5.3.7 Compatibility Testing

Compatibility testing to determine the corrosion rate between the injected waste stream and the K-55 alloy used in the Plant Well No. 1 (WDW147) injection tubing has been performed on a quarterly basis since 1986. Corrosion on the 3, 6, and 12-month coupons has been observed as minimal. The average corrosion rates present on the 12-month coupons from January 1986 to January 1992 was 0.28 mills/yr. The tubing in WDW147 is L-80 grade material, installed during the workover in 2010, which is essentially the same material of construction as N-80. L-80 grade has slightly more controlled chemistry and mechanical properties than the N-80 grade. N-80 and L-80 grade tubulars both have minimum yield strength of 80,000 psi. The primary difference between N-80 and L-80 grade API tubulars is the normalization process, heat treating and quenching. L-80 grade tubulars have hardness maxima and ranges of allowable hardness values which are controlled during the normalization process. N-80 tubulars have minimum hardness standards without a maximum hardness limit. The L-80 grade tubular has a maximum Rockwell hardness value of 22.

The metallurgy for L-80, Group 1 material is also slightly more controlled than N-80 grade tubulars. For L-80 grade material, the percent by weight upper limits are set for carbon (0.43%), manganese (1.90%), nickel (0.25%), copper (0.35%), and silicon (0.45%) which are not set for N-80 grade material. WDW147 is SASOL Chemicals (USA), LLC's backup well and has not been put back into injection service following the workover. The annual testing is performed with fresh water. The tubulars and completion equipment installed in WDW147 during the 2010 workover have not contacted SASOL's waste water.

The corrosion rate in Plant Well No. 2 (WDW319) as a result of exposure of the permitted injection stream and the P-110, N-80, and K-55 alloy has been recorded as minimal. The surface piping to Plant Well No. 2 (WDW319) has been constructed to contain corrosion coupons that are representative of the tubular materials of Plant Well No.2 (WDW319) (N-80 and P-110 carbon steel) as well as the K-55 carbon steel coupons. These coupons are located in a segment of the injection line subject to the Plant Well No. 2 (WDW319) wellhead pressure, temperature, and flow rate 5-5.

The Sasol Chemicals (USA), LLC Greens Bayou Plant waste stream is primarily caustic, which has proven to be relatively non-corrosive to carbon steel process piping over several decades. Plant Well No. 1 (WDW147) was installed in 1978 using K-55 carbon steel well tubulars and a carbon steel packer, and the well has never required a major workover. Plant Well No. 2 (WDW319) was installed in 2000 also using K-55 carbon steel well tubulars and has never required a major workover.

Both Plant Well Nos. 1 (WDW147) and 2 (WDW319) were cemented using lightweight and dense Class H cement mixtures, and annual mechanical integrity testing has verified that no upward migration of fluid has occurred behind the cases – verifying the integrity of the cement.

Formation water/waste compatibility sampling during the drilling of Plant Well No. 1 (WDW147) verified that no compatibility issues exist. Subsequent testing verified no compatibility problems between the waste and KCl fluids utilized during the annual injectivity testing. Core sample analysis completed during the completion of Plant Well No. 2 (WDW319) indicates minimal incompatibility between the Sasol waste and the formation fluid.

The coupons were continuously exposed to the deep well injectate and were evaluated on a quarterly basis, with the results submitted to the TCEQ with the Quarterly Injection reports. The coupons also showed very low rates of corrosion.

REFERENCES

Driscoll, F. G., 1986, Groundwater and Wells: 2nd ed., Johnson Division, St. Paul, Minnesota, p. 658-665.

Environmental Protection Agency, 1987, Technical Assistance Document: Corrosion, Its Detection and Control in Injection Wells: EPA 570/9-87-002, Washington, D. C.

Larrabee, C. P., 1946, Effect of Composition and Environment on Corrosion of Iron and Steel: Corrosion of Metals, p. 30-50.

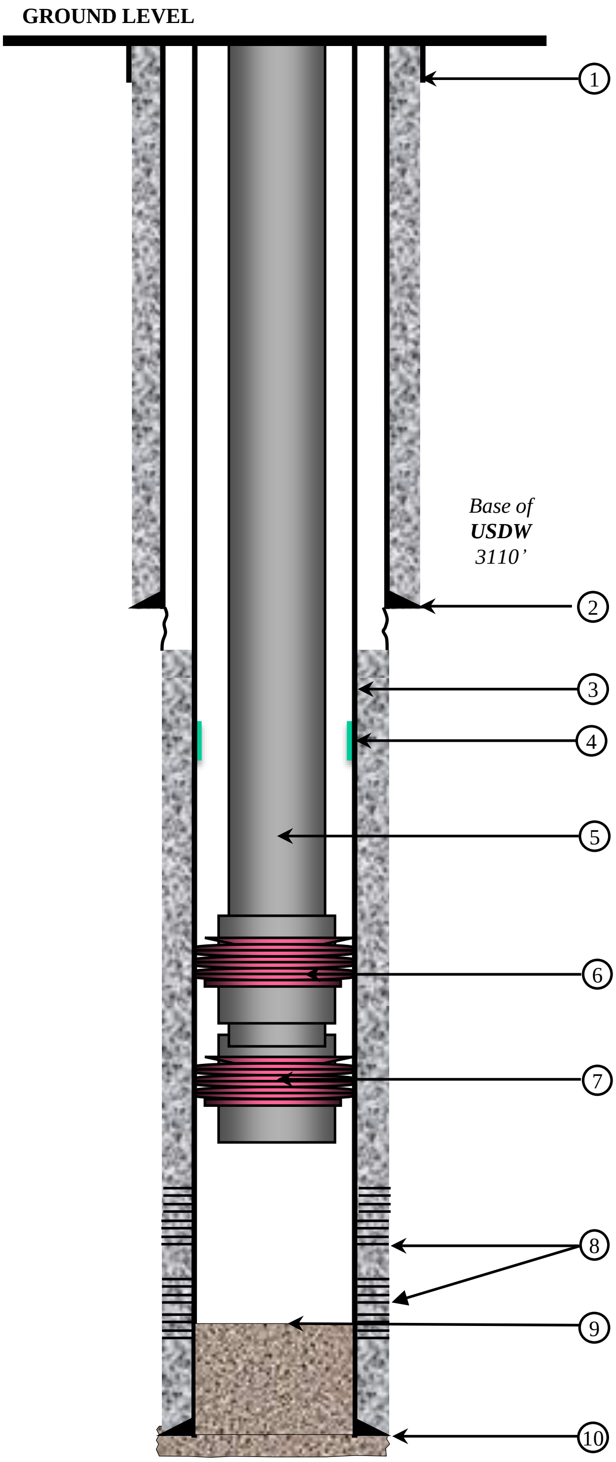
Perry, R. H., et al., 1973, Chemical Engineers Handbook: 5th ed., McGraw-Hill, Inc., New York, p. 23-1 to 23-7.

FIGURES

SASOL Chemicals (USA), LLC
Greens Bayou, Texas
Injection Well No. 1 (WDW147)
Well Schematic
Status: Active/Standby

All depths reference RKB

KB = 16' above Bradenhead Flange



COMPLETION DETAIL

1. Conductor Pipe: 20", ½" wall. Driven from surface to 83'.
2. Surface Casing: 10-3/4", 40.5-ppf, K-55, ST&C. Set from surface to 2728' in a 15" hole. Cemented to surface with 1100 sxs Lite-Wate lead and followed with 600 sxs Class H tail.
3. Protection Casing: 7", 23.0-ppf, K-55, ST&C, from surface to 5400', and 7", 26-ppf, K-55, ST&C, from 5400' to 7305', set in a 9-7/8" hole. Cemented with 520 sxs Lite-Wate lead and followed with 300 sxs Class H tail.
4. HOMCO Casing Patch installed in the 7", 23-ppf casing from 4113' to 4073'. (6.066" ID through casing patch)
5. Injection Tubing: 4-1/2", 11.6-ppf, L-80, LTC from surface to 6475' with cross Over, 4-1/2" 8rd, box by 3-1/2", EUE, 8rd pin (0.89') to Baker Locator Seal Assembly Model G-22 Size 80-40 w/ 1 seal unit, spacer tube, 4 seal units, & ½ mule shoe guide, 4" O.D. seal units (11.10'). Bottom of mule shoe at 6,487'. Minimum ID through seal assembly is 2.985". Note: Locator depth of 6476.4' from tubing tally, 4' deeper than the top of FB-1 packer at 6472'.
6. Injection Packer (top): 6472', Baker Model FB-1 Retainer Production Packer with a 10' 80-40 seal bore extension (4" ID) and Locator Seal Assembly Model G-22 Size 80-40 w/ 4 seal units and ½ mule shoe guide, 4" OD seal units. Bottom of mule shoe guide at 6489.6'.
7. Injection Packer (top): 6486', Baker Model FB-1 Retainer Production Packer with a 10' 80-40 seal bore extension (4" ID). Estimated bottom of guide at 6498.5'.
8. Perforated Completion: perforated with 4 shots per foot from:
   - 6620' to 6680'
   - 6700' to 6780'
9. Fill tagged: 6720' (RTS: 10/26/13)
10. Drilled to a total depth of 7336'.

Base of USDW: 3110'.

Regulatory Intervals:

- Confining Zone: 4760' to 5135' (Anahuac Fm.)
- Injection Zone: 5135' to 7410' (Frio Fm.)
- Injection Interval: 6564' to 6816' (Frio E&F Sand)
- Injection Interval: 6826' to 6980' (Frio A&B Sand)
- Injection Interval: 7097' to 7286' (Frio C Sand)

Depths referenced to ISF/Sonic Log dated 08/27/78.

Figure 5-1
Wellbore Diagram Injection Well No. 1 (WDW147)

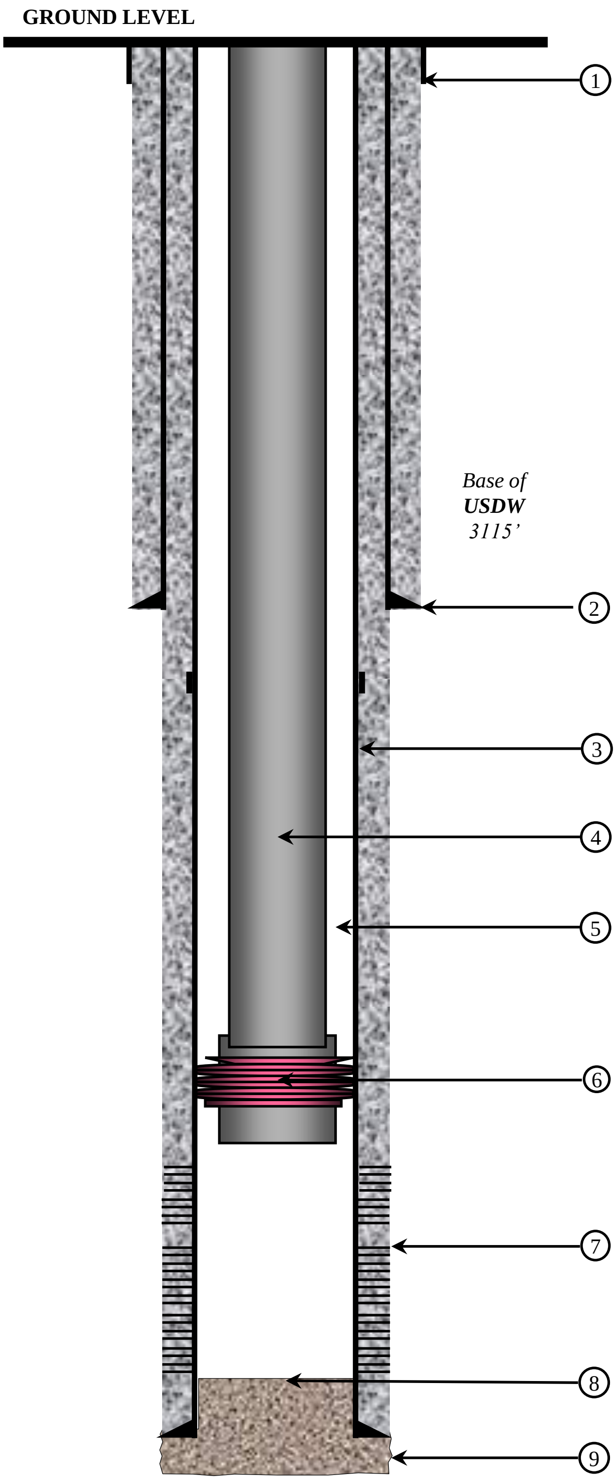
GEOSTOCK SANDIA ENTREPOSE
8860 Fallbrook Drive Houston, TX 77064 USA Tel: (346) 314 - 4347 Fax: (832) 478 - 5172

Drawn by: EAM	Date: 10/02/2000	*Drawing not to scale*
Revised 04/20/2018 by EDG for HWDIR June 2019 Submittal		

SASOL Chemicals (USA), LLC
Greens Bayou, Texas
Injection Well No. 2 (WDW319)
Well Schematic
Status: Active

All depths reference RKB

KB = 19.5' above Ground Level



COMPLETION DETAIL

1. Conductor Pipe: 20", ½" wall. Set from surface to 98.5'.
2. Surface Casing: 13-3/8", 61.0-ppf, J-55, ST&C. Set from surface to 3300' in 17-1/2" hole. Cemented to surface.
3. Protection Casing: 9-5/8", 47.0-ppf, N-80, LT&C. Set from surface to 7352', set in a 12-1/4" hole. Weatherford Cement Stage Tool at 3659'. Weatherford External Casing Patch w/Seal Top at 3660' and bottom of Overshot at 3664'.
4. Injection Tubing: 7", 26.0-ppf, P-110, LT&C. Baker KC-22 Anchor with A-Ryte Packing, Size 190-73. Minimum ID through anchor is 6.00". Set from surface to 6497'.
5. Annulus Fluid: Filled with 10-ppg NaCl brine with 20 gallons per 100 bbls of CIB corrosion inhibitor.
6. Injection Packer: 6498' to 6507', Baker Model FA; Size 192FA73X6.059 with Aflas elastomers, minimum ID of 4.778".
7. Perforated Completion: perforated with 5 shots per foot from:
   - 6850' to 6865'
   - 6888' to 6903'
   - 6920' to 6935'
   - 6954' to 6974'
   - 7114' to 7144'
   - 7216' to 7236'
   - 7240' to 7260'
8. Fill tagged at 7313', RTS 8/09/07
9. Drilled to a total depth of 7408'
10. Base of USDW: 3115'.

Note: During remedial cleanout 3/5/02, unable to run 4-1/2" bit past 6507'; Max OD tool run thorough assembly was 3.668".

- Regulatory Intervals:
  - Confining Zone: 4758' to 5134' (Anahuac Fm.)
  - Injection Zone: 5134' to 7410' (Frio Fm.)
  - Injection Interval: 6580' to 6821' (Frio E&F Sand)
  - Injection Interval: 6830' to 6984' (Frio A&B Sand)
  - Injection Interval: 7100' to 7290' (Frio C Sand)

  Depths referenced to WDW319, Induction Log dated 8/12/00

Figure 5-2

Wellbore Diagram Injection Well No. 2 (WDW319)

GEOSTOCK SANDIA
ENTREPOSE
8860 Fallbrook Drive Houston, TX 77064 USA Tel: (346) 314 - 4347 Fax: (832) 478 - 5172

Drawn by: EAM	Date: 02/12/2003	*Drawing not to scale*
Revised 4/20/2018 by EDG for HWDIR June 2019 Submittal		

TABLES

TABLE 5-1

CASING AND TUBING DIMENSIONS AND PARAMETERS INJECTION WELL NO. 1 (WDW147)

Unit	Size (inch)	Weight (lb/ft)	Grade	Depth (feet)	Burst/Collapse (psi)	Tensile Strength (lbs)
Conductor	20	--	--	83	--	--
Surface Casing	10-3/4	40.5	K-55	2,728	3,130/1,580	450,000
Protection Casing	7	23.0	K-55	0-5,400	4,360/3,270	341,000
Protection Casing	7	26.0	K-55	5,400 - 7,305	4,980/4,320	401,000
Injection Tubing	4-1/2	11.6	L-80	6,475	7,780/6,350	212,000

TABLE 5-2

CEMENTING DATA INJECTION WELL NO. 1 (WDW147)

Unit	Type/Class	Additives (feet)	Calculated Annular Volume* (gallons)	Pumped Volume* (gallons)
Surface Casing	Lite-Wate Cement Class H Cement	3% Salt 10% Salt	12,217	21,596
Protection Casing	Lite-Wate Cement Class H Cement	None 10% Salt 0.8% Halad 9	14,847	10,365

**volume Calculations contained in Appendix 5-2*

TABLE 5-3

CASING AND TUBING DIMENSIONS AND PARAMETERS
INJECTION WELL NO. 2 (WDW319)

Unit	Size (inch)	Weight (lb/ft)	Grade	Depth (feet)	Burst/Collapse (psi)	Tensile Strength (lbs)
Conductor	20	--	--	98.5	--	--
Surface Casing	13-3/8	61.0	J-55	3,300	3,090/1,540	595,000
Protection Casing	9-5/8	47.0	N-80	7,352	6,870/4,750	905,000
Injection Tubing	7	26.0	P-110	6,497	9,960/6,230	693,000

TABLE 5-4

CEMENTING DATA
INJECTION WELL NO. 2 (WDW319)

Unit	Type/Class	Additives (feet)	Calculated Annular Volume* (gallons)	Pumped Volume* (gallons)
Surface Casing	15% Poz & 85% Class H Cement Class H Cement	5% Salt, 8% Gel None	17,147	50,238
Protection Casing	35% POZ Class A Cement Class H Cement	5% Salt, 8% Gel 3% R-3 10% Salt, 2% Gel 0.1% CD-32	30,581	11,654

**volume Calculations contained in Appendix 5-2*

TABLE 5-5
CLASS I INJECTION CHEMICALS AND CORROSION EFFECTS

Injected Chemical	Effect On Corrosion
Acids Pickle Liquor (HCI, H_2SO_4, $FeCl_3$, $Fe_2(SO_4)_3$) $FeCl_3$ (Ferric Chloride) HCI (Hydrochloric Acid) H_2SO_4 (Sulfuric Acid) HF (Hydrofluoric Acid) Nonspecified Acids	Strong oxidizers, enhance chemical corrosion.
Bases and Caustics Nonspecified Alkalines Nonspecified Caustics NaOH (Sodium Hydroxide) NH_3 (Ammonia)	Enhance chemical and electrochemical corrosion
Organic Compounds Phenols Isopropyl Alcohol Formates Carbon Tetrachloride Organic Cyanides Nonspecified Herbicides Nonspecified Pesticides	May cause decay of plastic and rubber well casing and tubing
Nonspecified Organic Wastes	May cause lack of oxygen allowing for growth of anaerobes
Dissolved Species	
NaCl (Sodium Chloride)	Electrolyte, enhances electrochemical corrosion.
Sulfates	Can react to form minor amounts of acid, nutrient for bacterial growth.
Nitrates	Can react to form minor amounts of acid, nutrient for bacterial growth.
Carbonates	Can raise TDS increasing electrolyte content, enhance electrochemical corrosion.
Sulfides	Can react to form minor amounts of acid, nutrient for bacterial growth.
Nonspecified Salts	Can raise TDS increasing electrolyte content, enhance electrochemical corrosion.
Phosphates	Can react to form minor amounts of acid, nutrient for bacterial growth.
Calcium Magnesium Iron Fluorine Sodium Chlorine	Can raise TDS increasing electrolyte content, enhance electrochemical corrosion.

APPENDICES

APPENDIX 5-1
CURRENT TCEQ STATE PERMITS

INJECTION WELL NO. 1 (WDW147)

Permit No. WDW147

This permit supersedes and replaces Permit No. WDW147 issued January 12, 2006.

Texas Commission on Environmental Quality

Austin, Texas

Permit to Conduct
Class I Underground Injection
Under Provisions of Texas Water Code
Chapter 27 and Texas Health and Safety
Code Chapter 361

I. Permittee

SASOL Chemicals (USA), LLC
1914 Haden Road
Houston, TX 77015

Owner

Merichem Company
5455 Old Spanish Trail
Houston, TX 77023

II. Type of Permit

Initial_____ Renewal__X__ Amended______
Commercial__X__ Noncommercial_X__
Hazardous__X__ Nonhazardous__X__
Onsite __X__ Offsite__X__
Authorizing Disposal of Waste from Captured Facility_____
Authorizing Disposal of Waste from Off-site Facilities Owned by Owner/Operator _X_

CONTINUED on Pages 2 through 6

The permittee is authorized to conduct injection in accordance with limitations, requirements, and other conditions set forth herein. This permit is granted subject to the rules and orders of the Commission, and the laws of the State of Texas. The permit will be in effect for ten years from the date of approval or until amended or revoked by the Commission. If this permit is appealed and the permittee does not commence any action authorized by this permit during judicial review, the term will not begin until judicial review is concluded.

DATE ISSUED: May 27, 2016

For The Commission

III. Nature of Business

Chemical manufacturing plant for cresylic acids and other chemicals and commercial underground disposal of industrial process aqueous wastes.

IV. General Description and Location of Injection Activity

The disposal well is used to dispose of hazardous and nonhazardous wastes generated by the permittee's facilities and from other sources during the manufacture cresylic acids and other chemicals. The well is located 4,000 feet from the north line and 16,900 feet from the east line of the Richard & Robert Vince Survey, A-76, Latitude 29°45'35" North, Longitude 95°10'35" West, Harris County, Texas. The injection zone is within the Frio and Vicksburg Formations at the depths of 5,119 to 7,394 feet below ground level. The authorized injection interval is within the Frio Formation at the depths of 6,548 to 7,270 feet below ground level.

For purposes of compliance with U.S. Environmental Protection Agency no-migration demonstration requirements pursuant to federal Land Disposal Restrictions, the authorized injection interval is divided into two sand packages designated as "A/B/C" sand and "E/F" sands.

V. Character of the Waste Streams

A. Industrial hazardous and nonhazardous waste authorized to be injected by this permit shall consist solely of the following waste streams:

1. Waste streams generated from plant operations and generated from off-site operations at facilities owned by the owner/operator.

2. Waste streams generated from offsite operations at facilities not owned by the owner/operator which are compatible with permitted waste streams, injection zone and well materials.

3. Other associated wastes such as groundwater and rainfall contaminated by the above authorized wastes, spills of the above authorized wastes, and wash waters and solutions used in cleaning and servicing the waste disposal well system equipment which are compatible with the permitted waste streams, injection zone and well materials.

4. Waste generated during well construction or closure of WDW147 and WDW319, and associated facilities that are compatible with permitted wastes, injection zone, and well materials.

B. The injection of wastes is limited to those wastes authorized in Provision V.A. above, into the Frio and Vicksburg Formations within the injection zone between the depths of 5,119 to 7,394 feet below ground level.

C. The pH of injected waste streams shall be greater than or equal to 4.5.

D. Except when authorized by the Executive Director, the specific gravity of injected fluids shall less than or equal to 1.25 as measured at 68°F.

VI. Waste Streams Prohibited From Injection

Unless authorized by Provision V.A., the following waste streams are prohibited:

A. Wastes prohibited from injection in 40 CFR Part 148, Subpart B, are specifically prohibited from injection by this permit, unless an exemption from prohibition has been granted pursuant to 40 CFR Part 148, Subpart C, or the wastes meet or exceed the applicable treatment standards in 40 CFR Part 268, Subpart D;

B. Any by-product material as defined by Texas Health and Safety Code §401.003(3);

C. Any low-level radioactive waste as defined by Texas Health and Safety Code §401.004;

D. Any naturally occurring radioactive material (NORM) waste as defined by Texas Health and Safety Code §401.003(26); and

E. Any oil and gas NORM waste as defined by Texas Health & Safety Code §401.003(27).

VII. Operating Parameters

The well shall be operated in compliance with the requirements of 30 TAC Chapters 305, 331, and 335; the plans and specifications of the permit application; and the following conditions:

A. Surface injection pressure shall not cause pressure in the injection zone to:

1. initiate any new fractures or propagate existing fractures in the injection zone;
2. initiate new fractures or propagate existing fractures in the confining zone; or
3. cause movement of fluid out of the injection zone that may contaminate underground sources of drinking water (USDWs), and fresh water.

B. The operating surface injection pressure shall not exceed 600 psig.

C. The maximum injection rate for WDW147 and WDW319 shall not exceed 750 gallons per minute (gpm) per well, when each well is completed in a separate sand package. If both wells are completed in a common sand package, the cumulative rate of injection shall not exceed 750 gpm.

D. The volume of wastewater injected shall not exceed 33,480,000 gallons per month, or 394,200,000 gallons per year, per well, when each well is completed in a separate sand package. If both wells are completed in a common sand package, the volume of wastewater injected shall not exceed 33,480,000 gallons per month, or 394,200,000 gallons per year.

E. A positive pressure of at least 100 psig over tubing injection pressures shall be maintained in the tubing-casing annulus for the purpose of leak detection. Temporary deviations from this requirement which are a part of normal well operations are authorized but may not exceed 15 minutes in duration. For 15 minutes after the pressure differential drops below 100 psig, the permittee shall conduct troubleshooting and proceed to restore a minimum 100 psig pressure differential. If a minimum 100 psig pressure differential cannot be achieved within 15 minutes, the permittee shall notify the Texas Commission on Environmental Quality (TCEQ) and commence shut-in procedures on the well. The permittee may continue to operate the well under flow conditions that maintain a minimum 100 psig pressure differential.

F. The permittee shall notify the Executive Director at least 24 hours prior to commencing any workover which involves taking the injection well out of service. Approval by the Executive Director shall be obtained before the permittee may begin work. Notification shall be in writing and shall include plans for the proposed work. The Executive Director may grant an exception in accordance with 30 TAC §331.63(i) when immediate action is required to comply with 30 TAC §331.63(b). Completion of the well outside the approved injection interval, by perforation of casing, setting of screen, or establishment of open hole section, requires that the permitted injection interval be changed according to 30 TAC §331.62(a)(3)(B) to include the depths of all well completion. Pressure control equipment shall be installed and maintained during workovers which involve the removal of tubing.

VIII. Monitoring and Testing Requirements

A. Monitoring and testing shall be in compliance with the requirements of 30 TAC §305.125, §331.64, the plans and specifications of the permit application, and the following conditions.

B. The integrity of the long string casing, injection tubing, and annular seal shall be tested by means of an approved pressure test with a liquid or gas annually and whenever there has been a well workover. The integrity of the cement within the injection zone shall be tested by means of an approved radioactive tracer survey annually. A radioactive tracer survey may be required after workovers that have the potential to damage the cement within the injection zone.

C. The pressure buildup in the injection zone shall be monitored annually, including at a minimum, a shutdown of the well for a sufficient time to conduct a valid observation of the pressure fall-off curve.

D. A temperature log, noise log, oxygen activation log or other approved log is required at least once every five years to test for fluid movement along the entire borehole.

E. A casing inspection, casing evaluation, or other approved log shall be run whenever the owner or operator conducts a workover in which the injection string is pulled, unless the Executive Director waives this requirement due to well construction or other factors which limit the test's reliability, or based upon the satisfactory results of a casing inspection log run within the previous five years. The Executive Director may require that a casing inspection log be run every five years if there is sufficient reason to believe the integrity of the long string casing of the well may be adversely affected by naturally occurring or man-made events.

F. Injection fluids shall be tested in accordance with 30 TAC §331.64(b) and the approved waste analysis plan.

G. The pH and specific gravity of the injected waste shall be monitored continuously at a minimum frequency of at least once every 24 hours and whenever the waste stream changes.

H. Corrosion monitoring of well materials shall be conducted quarterly and in accordance with 30 TAC §331.64(g). Test materials shall be the same as those used in the wellhead, injection tubing, packer, and long string casing, and shall be continuously exposed to the waste fluids except when the well is taken out of service.

I. The permittee shall ensure that all waste analyses used for waste identification or verification and other analyses for environmental monitoring have been performed in accordance with methods specified in the current editions of EPA SW-846, ASTM or other methods accepted by the TCEQ. The permittee shall have a Quality Assurance/Quality Control program that is consistent with EPA SW-846 and the TCEQ Quality Assurance Project Plan.

IX. Record Keeping Requirements

The permittee shall keep complete and accurate records as required by 30 TAC Chapters 305, 331, and 335.

X. Financial Assurance for Well Closure

In accordance with 30 TAC Chapter 37, §305.154(a)(9), and §§331.142-144, the permittee shall secure and maintain financial assurance, in a form approved by the Executive Director, in the amount of $319,610 (cost estimate prepared July 2015 in current dollars). Adjustments to the cost estimates for plugging and abandonment in current dollars, and to financial assurance based thereon, shall be made in accordance with 30 TAC §331.143(d) and Chapter 37.

XI. Additional Requirements

A. The base of the wellhead shall be enclosed by a diked, impermeable pad or sump to protect the ground surface from spills and releases. Any liquid collected shall be disposed of in an appropriate manner.

B. Acceptance of this permit by the permittee constitutes an acknowledgment and agreement that the permittee will comply with all the terms and conditions embodied in the permit, and the rules and other orders of the Commission.

C. This permit is subject to further orders and rules of the Commission. In accordance with the procedures for amendments and orders, the Commission may incorporate into permits already granted, any condition, restriction, limitation, or provision reasonably necessary for the administration and enforcement of Texas Water Code, Chapter 27 and Texas Health and Safety Code, Chapter 361.

D. This permit does not convey any property rights of any sort, nor any exclusive privilege, and does not become a vested right in the permittee.

E. The issuance of this permit does not authorize any injury to persons or property or an invasion of other property rights, or any infringement of state or local law or regulations.

F. The following rules are incorporated as terms and conditions of this permit by reference:

1. 30 TAC Chapter 305, Consolidated Permits;
2. 30 TAC Chapter 331, Underground Injection Control; and
3. 30 TAC Chapter 335, Industrial Solid Waste and Municipal Hazardous Waste.

G. The express incorporation of the above rules as terms and conditions of this permit does not relieve the permittee of an obligation to comply with all other laws or regulations which are applicable to the activities authorized by this permit.

H. Incorporated Application Materials. This permit is based on, and the permittee shall follow, the plans and specifications contained in the Class I Underground Injection Control Application dated July 15, 2015 and revised on November 19, 2015 which are hereby approved subject to the terms of this permit and any other orders of the TCEQ.

I. All pre-injection units servicing this well must be authorized under TCEQ permit HW 50387 under 30 TAC Chapter 335 or must be exempt from the requirement for a permit under 30 TAC §335.69.

J. The Texas solid waste registration (SWR) number for this site is 30595.

INJECTION WELL NO. 2 (WDW319)

Permit No. WDW319

This permit supersedes
and replaces Permit
No. WDW319 issued
January 12, 2006.

Texas Commission on Environmental Quality

Austin, Texas

Permit to Conduct
Class I Underground Injection
Under Provisions of Texas Water Code
Chapter 27 and Texas Health and Safety
Code Chapter 361

I. Permittee

SASOL Chemicals (USA), LLC
1914 Haden Road
Houston, TX 77015

Owner

Merichem Company
5455 Old Spanish Trail
Houston, TX 77023

II. Type of Permit

Initial______ Renewal__X__ Amended______
Commercial__X__ Noncommercial__X__
Hazardous__X__ Nonhazardous__X__
Onsite __X__ Offsite__X__
Authorizing Disposal of Waste from Captured Facility______
Authorizing Disposal of Waste from Off-site Facilities Owned by Owner/Operator _X_

CONTINUED on Pages 2 through 6

The permittee is authorized to conduct injection in accordance with limitations, requirements, and other conditions set forth herein. This permit is granted subject to the rules and orders of the Commission, and the laws of the State of Texas. The permit will be in effect for ten years from the date of approval or until amended or revoked by the Commission. If this permit is appealed and the permittee does not commence any action authorized by this permit during judicial review, the term will not begin until judicial review is concluded.

DATE ISSUED: May 27, 2016

____
For The Commission

III. Nature of Business

Chemical manufacturing plant for cresylic acids and other chemicals and commercial underground disposal of industrial process aqueous wastes.

IV. General Description and Location of Injection Activity

The disposal well is used to dispose of hazardous and nonhazardous wastes generated by the permittee's facilities and from other sources during the manufacture cresylic acids and other chemicals. The well is located 4,140 feet from the north line and 17,145 feet from the east line of the Richard & Robert Vince Survey, A-76, Latitude 29°45'33.7" North, Longitude 95°10'37.9" West, Harris County, Texas. The injection zone is within the Frio and Vicksburg Formations at the depths of 5,119 to 7,394 feet below ground level. The authorized injection interval is within the Frio Formation at the depths of 6,564 to 7,274 feet below ground level.

For purposes of compliance with U.S. Environmental Protection Agency no-migration demonstration requirements pursuant to federal Land Disposal Restrictions, the authorized injection interval is divided into two sand packages designated as "A/B/C" sand and "E/F" sands.

V. Character of the Waste Streams

A. Industrial hazardous and nonhazardous waste authorized to be injected by this permit shall consist solely of the following waste streams:

1. Waste streams generated from plant operations and generated from off-site operations at facilities owned by the owner/operator.
2. Waste streams generated from offsite operations at facilities not owned by the owner/operator which are compatible with permitted waste streams, injection zone and well materials.
3. Other associated wastes such as groundwater and rainfall contaminated by the above authorized wastes, spills of the above authorized wastes, and wash waters and solutions used in cleaning and servicing the waste disposal well system equipment which are compatible with the permitted waste streams, injection zone and well materials.
4. Waste generated during well construction or closure of WDW147 and WDW319, and associated facilities that are compatible with permitted wastes, injection zone, and well materials.

B. The injection of wastes is limited to those wastes authorized in Provision V.A. above, into the Frio and Vicksburg Formations within the injection zone between the depths of 5,119 to 7,394 feet below ground level.

C. The pH of injected waste streams shall be greater than or equal to 4.5.

D. Except when authorized by the Executive Director, the specific gravity of injected fluids shall less than or equal to 1.25 as measured at 68°F.

VI. Waste Streams Prohibited From Injection

Unless authorized by Provision V.A., the following waste streams are prohibited:

A. Wastes prohibited from injection in 40 CFR Part 148, Subpart B, are specifically prohibited from injection by this permit, unless an exemption from prohibition has been granted pursuant to 40 CFR Part 148, Subpart C, or the wastes meet or exceed the applicable treatment standards in 40 CFR Part 268, Subpart D;

B. Any by-product material as defined by Texas Health and Safety Code §401.003(3);

C. Any low-level radioactive waste as defined by Texas Health and Safety Code §401.004;

D. Any naturally occurring radioactive material (NORM) waste as defined by Texas Health and Safety Code §401.003(26); and

E. Any oil and gas NORM waste as defined by Texas Health & Safety Code §401.003(27).

VII. Operating Parameters

The well shall be operated in compliance with the requirements of 30 TAC Chapters 305, 331, and 335; the plans and specifications of the permit application; and the following conditions:

A. Surface injection pressure shall not cause pressure in the injection zone to:

1. initiate any new fractures or propagate existing fractures in the injection zone;
2. initiate new fractures or propagate existing fractures in the confining zone; or
3. cause movement of fluid out of the injection zone that may contaminate underground sources of drinking water (USDWs), and fresh water.

B. The operating surface injection pressure shall not exceed 1,200 psig.

C. The maximum injection rate for WDW147 and WDW319 shall not exceed 750 gallons per minute (gpm) per well, when each well is completed in a separate sand package. If both wells are completed in a common sand package, the cumulative rate of injection shall not exceed 750 gpm.

D. The volume of wastewater injected shall not exceed 33,480,000 gallons per month, or 394,200,000 gallons per year, per well, when each well is completed in a separate sand package. If both wells are completed in a common sand package, the volume of wastewater injected shall not exceed 33,480,000 gallons per month, or 394,200,000 gallons per year.

E. A positive pressure of at least 100 psig over tubing injection pressures shall be maintained in the tubing-casing annulus for the purpose of leak detection.

Temporary deviations from this requirement which are a part of normal well operations are authorized but may not exceed 15 minutes in duration. For 15 minutes after the pressure differential drops below 100 psig, the permittee shall

conduct troubleshooting and proceed to restore a minimum 100 psig pressure differential. If a minimum 100 psig pressure differential cannot be achieved within 15 minutes, the permittee shall notify the Texas Commission on Environmental Quality (TCEQ) and commence shut-in procedures on the well. The permittee may continue to operate the well under flow conditions that maintain a minimum 100 psig pressure differential.

F. The permittee shall notify the Executive Director at least 24 hours prior to commencing any workover which involves taking the injection well out of service. Approval by the Executive Director shall be obtained before the permittee may begin work. Notification shall be in writing and shall include plans for the proposed work. The Executive Director may grant an exception in accordance with 30 TAC §331.63(i) when immediate action is required to comply with 30 TAC §331.63(b). Completion of the well outside the approved injection interval, by perforation of casing, setting of screen, or establishment of open hole section, requires that the permitted injection interval be changed according to 30 TAC §331.62(a)(3)(B) to include the depths of all well completion. Pressure control equipment shall be installed and maintained during workovers which involve the removal of tubing.

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C. The pressure buildup in the injection zone shall be monitored annually, including at a minimum, a shutdown of the well for a sufficient time to conduct a valid observation of the pressure fall-off curve.

D. A temperature log, noise log, oxygen activation log or other approved log is required at least once every five years to test for fluid movement along the entire borehole.

E. A casing inspection, casing evaluation, or other approved log shall be run whenever the owner or operator conducts a workover in which the injection string is pulled, unless the Executive Director waives this requirement due to well construction or other factors which limit the test’s reliability, or based upon the satisfactory results of a casing inspection log run within the previous five years. The Executive Director may require that a casing inspection log be run every five years if there is sufficient reason to believe the integrity of the long string casing of the well may be adversely affected by naturally occurring or man-made events.

F. Injection fluids shall be tested in accordance with 30 TAC §331.64(b) and the approved waste analysis plan.

G. The pH and specific gravity of the injected waste shall be monitored continuously at a minimum frequency of at least once every 24 hours and whenever the waste stream changes.

H. Corrosion monitoring of well materials shall be conducted quarterly and in accordance with 30 TAC §331.64(g). Test materials shall be the same as those used in the wellhead, injection tubing, packer, and long string casing, and shall be continuously exposed to the waste fluids except when the well is taken out of service.

I. The permittee shall ensure that all waste analyses used for waste identification or verification and other analyses for environmental monitoring have been performed in accordance with methods specified in the current editions of EPA SW-846, ASTM or other methods accepted by the TCEQ. The permittee shall have a Quality Assurance/Quality Control program that is consistent with EPA SW-846 and the TCEQ Quality Assurance Project Plan.

IX. Record Keeping Requirements

The permittee shall keep complete and accurate records as required by 30 TAC Chapters 305, 331, and 335.

X. Financial Assurance for Well Closure

In accordance with 30 TAC Chapter 37, §305.154(a)(9), and §§331.142-144, the permittee shall secure and maintain financial assurance, in a form approved by the Executive Director, in the amount of $319,610 (cost estimate prepared July 2015 in current dollars). Adjustments to the cost estimates for plugging and abandonment in current dollars, and to financial assurance based thereon, shall be made in accordance with 30 TAC §331.143(d) and Chapter 37.

XI. Additional Requirements

A. The base of the wellhead shall be enclosed by a diked, impermeable pad or sump to protect the ground surface from spills and releases. Any liquid collected shall be disposed of in an appropriate manner.

B. Acceptance of this permit by the permittee constitutes an acknowledgment and agreement that the permittee will comply with all the terms and conditions embodied in the permit, and the rules and other orders of the Commission.

C. This permit is subject to further orders and rules of the Commission. In accordance with the procedures for amendments and orders, the Commission may incorporate into permits already granted, any condition, restriction, limitation, or provision reasonably necessary for the administration and enforcement of Texas Water Code, Chapter 27 and Texas Health and Safety Code, Chapter 361.

D. This permit does not convey any property rights of any sort, nor any exclusive privilege, and does not become a vested right in the permittee.

E. The issuance of this permit does not authorize any injury to persons or property or an invasion of other property rights, or any infringement of state or local law or regulations.

F. The following rules are incorporated as terms and conditions of this permit by reference:

1. 30 TAC Chapter 305, Consolidated Permits;
2. 30 TAC Chapter 331, Underground Injection Control; and
3. 30 TAC Chapter 335, Industrial Solid Waste and Municipal Hazardous Waste.

G. The express incorporation of the above rules as terms and conditions of this permit does not relieve the permittee of an obligation to comply with all other laws or regulations which are applicable to the activities authorized by this permit.

H. Incorporated Application Materials. This permit is based on, and the permittee shall follow, the plans and specifications contained in the Class I Underground Injection Control Application dated July 15, 2015 and revised on November 19, 2015 which are hereby approved subject to the terms of this permit and any other orders of the TCEQ.

I. All pre-injection units servicing this well must be authorized under TCEQ permit HW 50387 under 30 TAC Chapter 335 or must be exempt from the requirement for a permit under 30 TAC §335.69.

J. The Texas solid waste registration (SWR) number for this site is 30595.

APPENDIX 5-2
CEMENT AND ANNULAR VOLUME CALCULATIONS

INJECTION WELL NO. 1 (WDW147)

APPENDIX 5-2
CEMENT AND ANNULAR VOLUME CALCULATIONS

INJECTION WELL NO. 1 (WDW147)

A. Surface Casing Annular Volume

$$Volume = (D^2 - d^2) \times L \times 0.0408$$

Where:

Volume = Total volume (gallons)

D = Hole Diameter (in)

d = Casing OD (in)

L = Setting depth (feet)

0.0408 = Conversion Factor (gal/ft-in^2)

$$Volume = (15^2 - 10.75^2) \times 2728 \times 0.0408$$

$$Volume = 12{,}217\ gals$$

B. Protection Casing Annular Volume

$$Volume = [(D^2 - d^2) \times (L - L_{sc}) \times 0.0408] + [(D_{sc}^2 - d^2) \times L_{sc} \times 0.0408]$$

Where:

Volume = Total volume (gallons)

D = Hole Diameter (in)

d = Casing OD (in)

L = Protective Casing Setting depth (feet)

L_{sc} = Surface Casing Setting depth (feet)

D_{sc} = Surface Casing ID (in)

0.0408 = Conversion Factor (gal/ft-in^2)

$$Vol = [(9.875^2 - 7^2) \times (7305 - 2728) \times 0.0408] + [(10.050^2 - 7^2) \times 2728 \times 0.0408]$$

$$Volume = 14{,}847\ gals$$

C. **Cement Volumes**

$$Volume = V_{sl} \times S \times 7.48052$$

Where:

Volume = Total volume (gallons)

V_{sl} = Slurry Volume (ft^3/sack))

S = Number of Sacks

7.48052 = Conversion Factor (gal/ft^3)

SURFACE CASING:

First Slurry

$$Volume = 1.97 \times 1100 \times 7.48052$$
$$Volume = 16{,}210\ gals$$

Second Slurry

$$Volume = 1.20 \times 600 \times 7.48052$$
$$Volume = 5{,}386\ gals$$

Total Volume: 16,210 + 5,386 = 21,596 *gals*

PROTECTION CASING:

First Slurry

$$Volume = 1.97 \times 520 \times 7.48052$$
$$Volume = 7{,}663\ gals$$

Second Slurry

$$Volume = 1.20 \times 300 \times 7.48052$$
$$Volume = 2{,}693\ gals$$

Total Volume: 7,663 + 2,693= 10,365 *gals*

INJECTION WELL NO. 2 (WDW319)

APPENDIX 5-2
CEMENT AND ANNULAR VOLUME CALCULATIONS

INJECTION WELL NO. 2 (WDW319)

A. Surface Casing Annular Volume

$$Volume = (D^2 - d^2) \times L \times 0.0408$$

Where:

Volume = Total volume (gallons)

D = Hole Diameter (in)

d = Casing OD (in)

L = Setting depth (feet)

0.0408 = Conversion Factor (gal/ft-in^2)

$$Volume = (17.5^2 - 13.375) \times 3300 \times 0.0408$$

$$Volume = 17{,}147\ gals$$

B. Protection Casing Annular Volume

$$Volume = [(D^2 - d^2) \times (L - L_{sc}) \times 0.0408] + [(D_{sc}^2 - d^2) \times L_{sc} \times 0.0408]$$

Where:

Volume = Total volume (gallons)

D = Hole Diameter (in)

d = Casing OD (in)

L = Protective Casing Setting depth (feet)

L_{sc} = Surface Casing Setting depth (feet)

D_{sc} = Surface Casing ID (in)

0.0408 = Conversion Factor (gal/ft-in^2)

$$Vol = [(12.25^2 - 9.625) \times (7352 - 3300) \times 0.0408] + [(12.515^2 - 9.625) \times 3300 \times 0.0408]$$

$$Volume = 30{,}581\ gals$$

C. Cement Volumes

$$Volume = V_{sl} \times S \times 7.48052$$

Where:

Volume = Total volume (gallons)

V_{sl} = Slurry Volume (ft^3/sack))

S = Number of Sacks

7.48052 = Conversion Factor (gal/ft^3)

Surface Casing:

First Slurry

$$Volume = 2.36 \times 2543 \times 7.48052$$
$$Volume = 44{,}894\ gals$$

Second Slurry

$$Volume = 1.06 \times 674 \times 7.48052$$
$$Volume = 5{,}344\ gals$$

Total Volume: 44,894 + 5,344 = 50,238 *gals*

Protection Casing:

First Slurry

$$Volume = 2.28 \times 550 \times 7.48052$$
$$Volume = 9{,}380\ gals$$

Second Slurry

$$Volume = 1.216 \times 250 \times 7.48052$$
$$Volume = 2{,}274\ gals$$

Total Volume: 9,380 + 2,274 = 11,654 *gals*

APPENDIX 5-3
INJECTION WELL DEVIATION SURVEYS

INJECTION WELL NO. 1 (WDW147)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form W-12
(1-1-71)

INCLINATION REPORT
(One Copy Must Be Filed With Each Completion Report.)

1. FIELD NAME (as per RRC Records or Wildcat): N/A	2. LEASE NAME: WDW-147	6. RRC District: #3
		7. RRC Lease Number. (Oil completions only)
3. OPERATOR: MERICHEM COMPANY		8. Well Number: 1
4. ADDRESS: 1914 HADEN ROAD HOUSTON, TEXAS 77015		9. RRC Identification Number (Gas completions only)
5. LOCATION (Section, Block, and Survey): RICHARD & ROBERT VINCE SURVEY A-76		10. County: Harris

RECORD OF INCLINATION

*11. Measured Depth (feet)	12. Course Length (Hundreds of feet)	*13. Angle of Inclination (Degrees)	14. Displacement per Hundred Feet (Sine of Angle X100)	15. Course Displacement (feet)	16. Accumulative Displacement (feet)
499	499	1/4	.44	2.20	2.20
1001	502	1/4	.44	2.21	4.41
1495	494	1/2	.87	4.30	8.71
2000	505	1/2	.87	4.39	13.10
2498	498	1/2	.87	4.33	17.43
3240	742	1-1/4	2.18	16.18	33.61
3480	240	1-1/4	2.18	5.23	38.84
3696	216	1-3/4	3.05	6.59	45.43
3730	34	1/4	.44	.15	45.58
3821	91	1	1.75	1.59	47.17
4045	224	3/4	1.31	2.93	50.10
4505	460	1	1.75	8.05	58.15
5025	520	1/4	.44	2.29	60.44
5521	496	1/2	.87	4.32	64.76
6025	504	1	1.75	8.82	73.58
6545	520	2	3.49	18.15	91.73

If additional space is needed, use the reverse side of this form.

17. Is any information shown on the reverse side of this form? [X] yes [ ] no
18. Accumulative total displacement of well bore at total depth of 7012 feet = 103.97 feet.
*19. Inclination measurements were made in — [ ] Tubing [ ] Casing [ ] Open hole [X] Drill Pipe
20. Distance from surface location of well to the nearest lease line ______ feet.
21. Minimum distance to lease line as prescribed by field rules ______ feet.
22. Was the subject well at any time intentionally deviated from the vertical in any manner whatsoever? ______
(If the answer to the above question is "yes", attach written explanation of the circumstances.)

INCLINATION DATA CERTIFICATION

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have personal knowledge of the inclination data and facts placed on both sides of this form and that such data and facts are true, correct, and complete to the best of my knowledge. This certification covers all data as indicated by asterisks (*) by the item numbers on this form.

L. Wendell Hefton

Signature of Authorized Representative

L. Wendell Hefton, Controller

Name of Person and Title (type or print)

Big "6" Drilling Company

Name of Company

Telephone: 713 783/2300

Area Code

OPERATOR CERTIFICATION

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have personal knowledge of all information presented in this report, and that all data presented on both sides of this form are true, correct, and complete to the best of my knowledge. This certification covers all data and information presented herein except inclination data as indicated by asterisks (*) by the item numbers on this form.

Alan Pennington

Signature of Authorized Representative

Alan Pennington, Geologist

Name of Person and Title (type or print)

Merichem Company

Operator

Telephone: (713) 455-1311

Area Code

Railroad Commission Use Only:

Approved By: ______ Title: ______ Date: ______

* Designates items certified by company that conducted the inclination surveys.

INJECTION WELL NO. 2 (WDW319)

Baker Atlas

BAKER HUGHES

DIRECTIONAL SURVEY

FILE NO:	20104
API NO:	42-201-N/A
Ver. 3.78	FINAL PRINT
COMPANY	MERSISOL
WELL	W.D.W. #319
FIELD	WASTE DISPOSAL WELL
COUNTY	HARRIS
STATE	TEXAS

LOCATION:
4140' FNL & 17,145' FEL OF THE
RICHARD & ROBERT VINCE SURVEY, (A-76)

OTHER SERVICES
HDIL/ZDL/CN/GR
STAR

PERMANENT DATUM	G.L.	ELEVATION	N/A
LOG MEASURED FROM	K.B.	19.5 FT	ABOVE P.D.
DRILL. MEAS. FROM	KELLY BUSHING		

ELEVATIONS:
KB 19.5 FT
DF 18.5 FT
GL N/A

DATE	12-AUG-2000		31-AUG-2000	
RUN / TRIP	1	1	2	1
SERVICE ORDER	354387		354387	
DEPTH DRILLER	3303 FT		7406 FT	
DEPTH LOGGER	3300 FT		7406 FT	
BOTTOM LOGGED INTERVAL	3292 FT		7399 FT	
TOP LOGGED INTERVAL	27 FT		3300 FT	
CASING DRILLER	20 IN	@100 FT	13.375 IN	@3303 FT
CASING LOGGER	100 FT		3300 FT	
BIT SIZE	17.5 IN		12.25 IN	
TYPE OF FLUID IN HOLE	LIGNOSULFONATE		KCL / NEW DRILL	
DENSITY / VISCOSITY	9.6 LB/G	72 S	9.8 LB/G	14 S
PH / FLUID LOSS	8.5	3.0 C3	9.8	6.0 C3
SOURCE OF SAMPLE	FLOWLINE		FLOWLINE	
RM AT MEAS. TEMP.	5.5 OHMM	@75 DEGF	0.27 OHMM	@89 DEGF
RMF AT MEAS. TEMP.	4.1 OHMM	@75 DEGF	0.19 OHMM	@89 DEGF
RMC AT MEAS. TEMP.	8.2 OHMM	@75 DEGF	0.32 OHMM	@89 DEGF
SOURCE OF RMF / RMC	MEASURED	CALCULATED	MEASURED	MEASURED
RM AT BHT	3.1 OHMM	@138 DEGF	0.16 OHMM	@156 DEGF
TIME SINCE CIRCULATION	6 HRS.		5.0	
MAX. RECORDED TEMP.	138 DEGF		156 DEGF	
EQUIP. NO. / LOCATION	HL-6547	VICTORIA	HL-6515	PEARLAND
RECORDED BY	S. SMART		D. SHORT	
WITNESSED BY	M. GRANT		J. SANDT	

IN MAKING INTERPRETATIONS OF LOGS OUR EMPLOYEES WILL GIVE CUSTOMER THE BENEFIT OF THEIR BEST JUDGEMENT. BUT SINCE ALL INTERPRETATIONS ARE OPINIONS BASED ON INFERENCES FROM ELECTRICAL OR OTHER MEASUREMENTS, WE CANNOT, AND WE DO NOT GUARANTEE THE ACCURACY OR CORRECTNESS OF ANY INTERPRETATION. WE SHALL NOT BE LIABLE OR RESPONSIBLE FOR ANY LOSS, COST, DAMAGES, OR EXPENSES WHATSOEVER INCURRED OR SUSTAINED BY THE CUSTOMER RESULTING FROM ANY INTERPRETATION MADE BY ANY OF OUR EMPLOYEES.

BOREHOLE RECORD		
BIT SIZE	FROM	TO
17.5 IN	100 FT	3303 FT

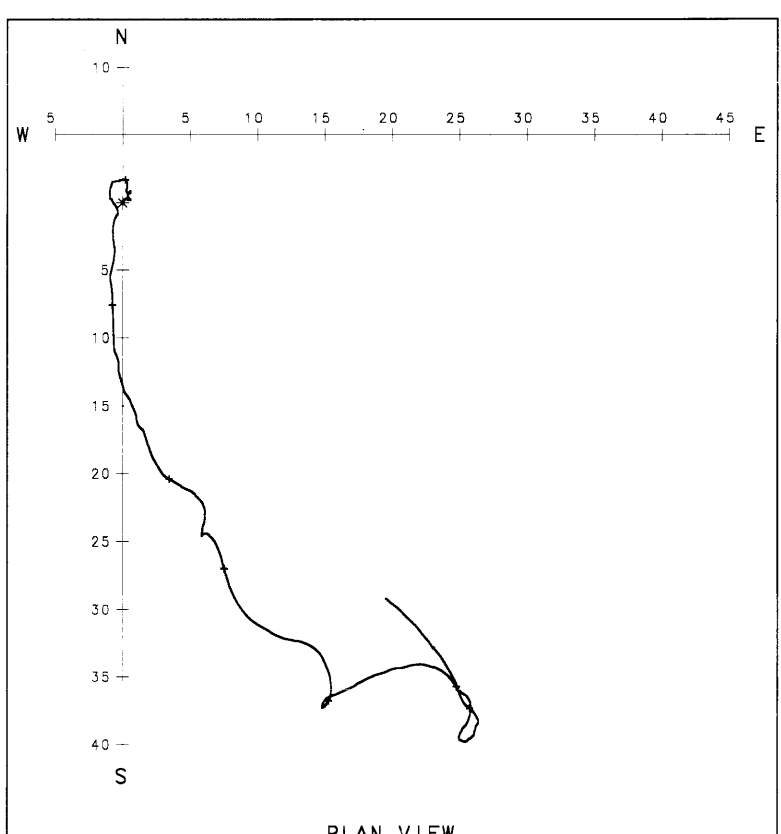
CASING RECORD				
SIZE	WEIGHT	GRADE	FROM	TO
20 IN	N/A	N/A	0 FT	100 FT

REMARKS

RUN 1 TRIP 1 :

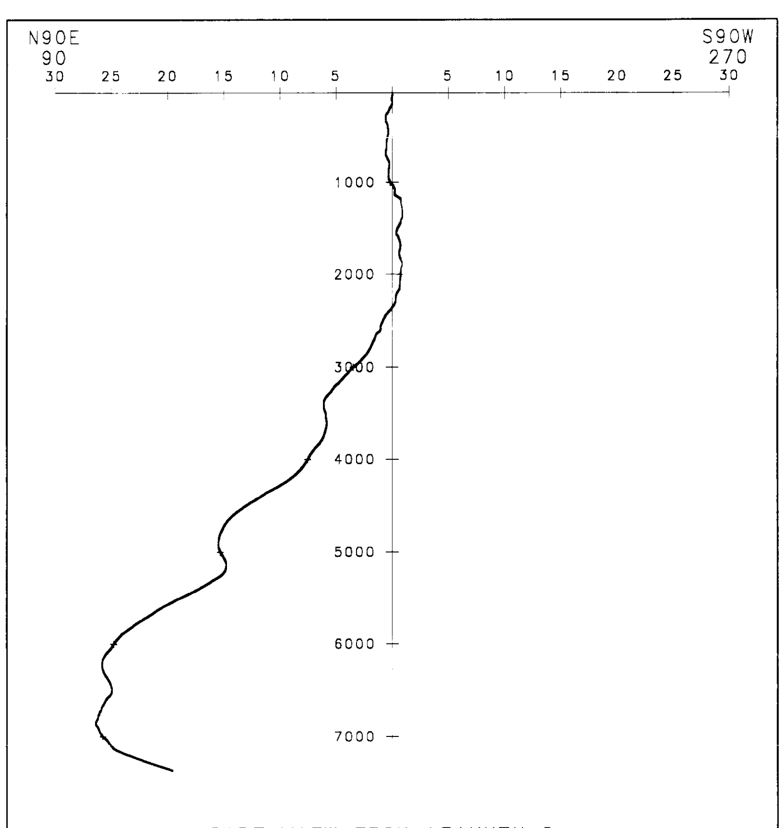
RUN 2 TRIP 1 :

EQUIPMENT DATA					
RUN	TRIP	TOOL	SERIES NO.	SERIAL NO.	POSITION



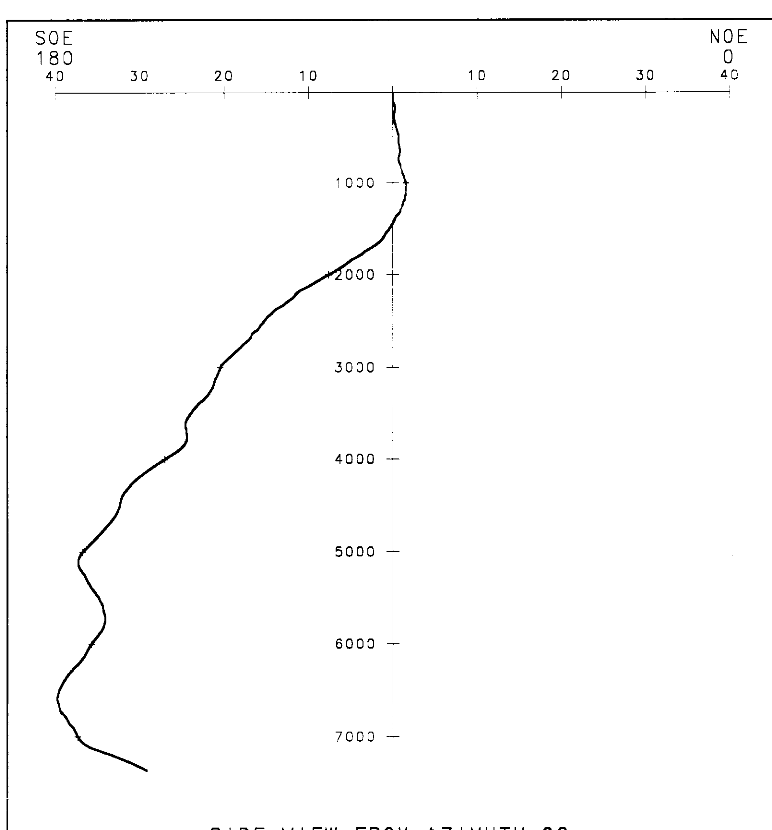
PLAN VIEW

: WELLBORE COURSE	FINAL EAST-WEST DRIFT	19.54 FT EAST
+ : MEASURED DEPTH TIE-IN	FINAL NORTH-SOUTH DRIFT	29.18 FT SOUTH
✳ : WELLHEAD POSITION	FINAL DRIFT DISTANCE	35.12 FT
	FINAL DRIFT DIRECTION	S 33.80 E
	DRIFT UNITS	FEET
	DEPTH UNITS	FEET



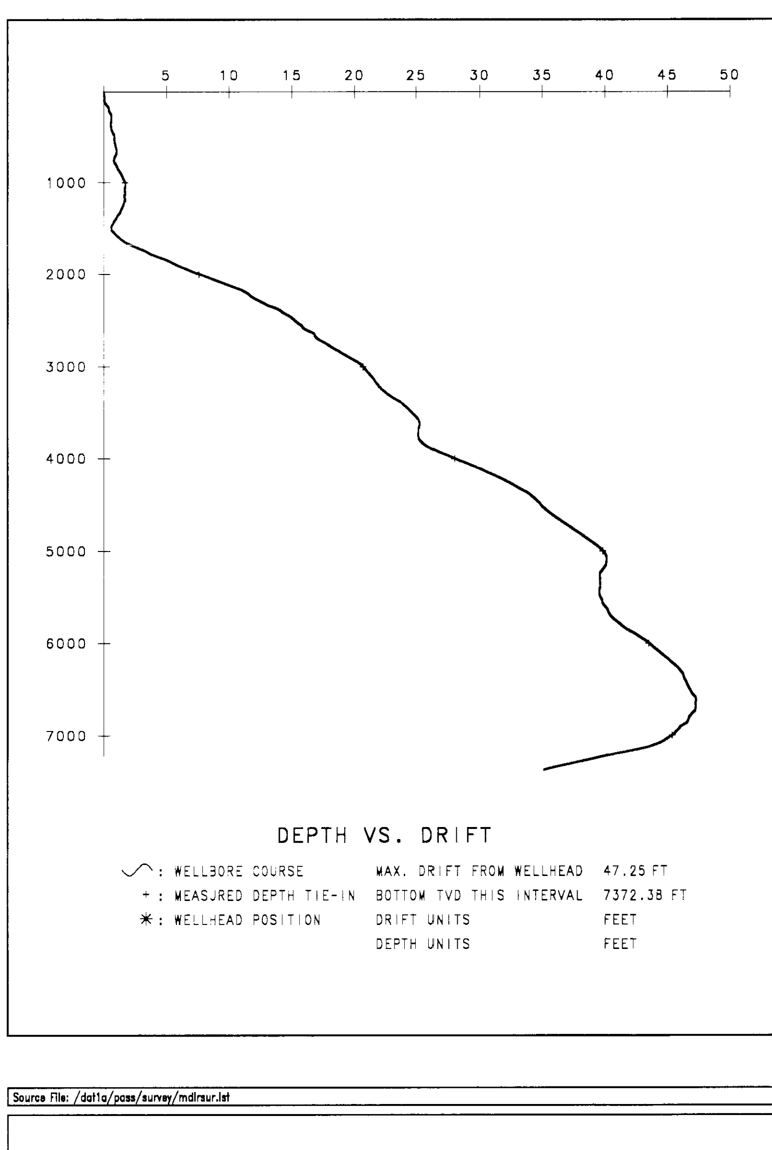
SIDE VIEW FROM AZIMUTH 0

: WELLBORE COURSE	MAX. DRIFT N90E	26.39 FT
+ : MEASURED DEPTH TIE-IN	MAX. DRIFT S90W	.97 FT
✳ : WELLHEAD POSITION	BOTTOM TVD THIS INTERVAL	7372.38 FT
	DRIFT UNITS	FEET
	DEPTH UNITS	FEET



SIDE VIEW FROM AZIMUTH 90

: WELLBORE COURSE	MAX. DRIFT S E	39.81 FT
+ : MEASURED DEPTH TIE-IN	MAX. DRIFT N E	1.73 FT
✳ : WELLHEAD POSITION	BOTTOM TVD THIS INTERVAL	7372.38 FT
	DRIFT UNITS	FEET
	DEPTH UNITS	FEET



DEPTH VS. DRIFT

: WELLBORE COURSE	MAX. DRIFT FROM WELLHEAD	47.25 FT
+ : MEASURED DEPTH TIE-IN	BOTTOM TVD THIS INTERVAL	7372.38 FT
✳ : WELLHEAD POSITION	DRIFT UNITS	FEET
	DEPTH UNITS	FEET

Source File: /dat1a/pass/survey/mdlrsur.lst

MERISOL
W.D.W. #319

DEPTH	DEVIATION ANGLE	DEVIATION AZIMUTH	T.V.D.	DRIFT COORDINATES STATION N-S	STATION E-W	TOTAL N-S	TOTAL E-W
27.00	.2	333.5	27.00	.00N	.00E	.00N	.00E
77.00	.1	78.0	77.00	.02N	.03E	.02N	.03E
127.00	.1	346.1	127.00	.02N	.03W	.05N	.00W
177.00	.4	53.6	177.00	.19N	.14E	.24N	.14E
227.00	.3	116.7	227.00	.00N	.19E	.24N	.33E
277.00	.2	118.4	277.00	.05S	.24E	.19N	.58E
327.00	.1	60.1	327.00	.02N	.02W	.21N	.56E
377.00	.2	314.1	377.00	.14N	.13W	.34N	.44E
427.00	.2	324.1	427.00	.15N	.09W	.49N	.35E
477.00	.3	19.0	477.00	.19N	.01E	.69N	.36E
527.00	.2	135.3	527.00	.00N	.11E	.69N	.47E
577.00	.1	9.6	577.00	.04N	.04E	.73N	.51E
627.00	.2	12.6	627.00	.10N	.01E	.83N	.52E
677.00	.0	176.8	677.00	.01N	.06E	.84N	.57E
727.00	.2	245.6	727.00	.12S	.08W	.72N	.49E
777.00	.2	314.5	777.00	.05N	.19W	.76N	.30E
827.00	.2	18.9	826.99	.23N	.02W	.99N	.28E
877.00	.3	340.9	876.99	.20N	.04E	1.19N	.32E
927.00	.2	358.9	926.99	.21N	.02E	1.41N	.34E
977.00	.3	335.7	976.99	.19N	.06W	1.59N	.28E
1027.00	.4	275.2	1026.99	.13N	.29W	1.72N	.01W
1077.00	.2	257.7	1076.99	.07S	.22W	1.65N	.23W
1127.00	.2	203.8	1126.99	.03N	.02E	1.68N	.20W
1177.00	.6	262.2	1176.99	.14S	.51W	1.54N	.71W
1227.00	.2	227.7	1226.99	.19S	.12W	1.35N	.83W
1277.00	.4	199.0	1276.99	.24S	.09W	1.11N	.92W
1327.00	.4	184.2	1326.99	.27S	.04W	.83N	.96W
1377.00	.4	174.3	1376.98	.48S	.01E	.36N	.96W
1427.00	.4	152.9	1426.98	.22S	.19E	.14N	.77W
1477.00	.5	138.6	1476.98	.31S	.19E	.17S	.58W
1527.00	.6	167.6	1526.98	.39S	.19E	.57S	.39W
1577.00	.5	225.7	1576.98	.37S	.05W	.94S	.44W
1627.00	.5	198.7	1626.98	.38S	.18W	1.32S	.62W
1677.00	.8	188.2	1676.97	.64S	.10W	1.96S	.72W
1727.00	1.1	171.2	1726.96	.87S	.02E	2.83S	.69W
1777.00	.8	183.9	1776.96	.79S	.09E	3.61S	.60W
1827.00	1.2	192.6	1826.95	.94S	.13W	4.56S	.73W
1877.00	.8	186.1	1876.94	.82S	.19W	5.38S	.92W
1927.00	1.0	169.7	1926.93	.81S	.08E	6.19S	.84W
1977.00	1.1	181.5	1976.93	.89S	.09E	7.08S	.76W

MERISOL
W.D.W. #319

DEPTH	DEVIATION ANGLE	DEVIATION AZIMUTH	T.V.D.	DRIFT COORDINATES STATION N-S	STATION E-W	TOTAL N-S	TOTAL E-W
2027.00	1.1	176.6	2026.92	1.02S	.03E	8.11S	.73W
2077.00	1.2	180.2	2076.91	.96S	.04E	9.07S	.69W
2127.00	1.2	177.7	2126.90	.97S	.02E	10.04S	.67W
2177.00	1.0	158.2	2176.89	1.00S	.10E	11.04S	.57W
2227.00	.5	159.6	2226.88	.58S	.22E	11.61S	.35W
2277.00	1.0	178.2	2276.88	.58S	.04E	12.19S	.31W
2327.00	.8	163.2	2326.87	.71S	.13E	12.90S	.18W
2377.00	1.0	162.7	2376.86	.93S	.27E	13.83S	.09E
2427.00	.9	148.6	2426.86	.59S	.38E	14.42S	.46E
2477.00	.5	154.7	2476.85	.60S	.25E	15.02S	.71E
2527.00	.6	158.6	2526.85	.43S	.20E	15.46S	.91E
2577.00	.5	186.2	2576.85	.42S	.11E	15.87S	1.01E
2627.00	1.1	143.9	2626.84	.65S	.20E	16.52S	1.21E
2677.00	.4	152.3	2676.84	.31S	.30E	16.83S	1.51E
2727.00	.8	162.8	2726.84	.54S	.19E	17.37S	1.70E
2777.00	.6	154.1	2776.84	.58S	.18E	17.95S	1.89E
2827.00	.8	162.2	2826.83	.61S	.22E	18.56S	2.11E
2877.00	.7	148.5	2876.83	.59S	.29E	19.15S	2.40E
2927.00	.8	145.9	2926.82	.62S	.38E	19.77S	2.78E
2977.00	.8	128.1	2976.82	.51S	.45E	20.28S	3.23E
3027.00	.6	120.2	3026.81	.24S	.45E	20.52S	3.68E
3077.00	.6	123.0	3076.81	.24S	.37E	20.75S	4.05E
3127.00	.5	119.8	3126.81	.26S	.39E	21.01S	4.44E
3177.00	.5	115.1	3176.81	.17S	.39E	21.18S	4.83E
3227.00	.6	153.1	3226.81	.21S	.37E	21.40S	5.20E
3301.00	.8	140.2	3300.80	.52S	.50E	21.91S	5.70E
3327.00	.6	152.4	3326.80	.25S	.19E	22.16S	5.89E
3377.00	.8	177.3	3376.80	.59S	.19E	22.75S	6.09E
3427.00	.5	181.6	3426.79	.54S	.00W	23.29S	6.09E
3477.00	.5	208.1	3476.79	.44S	.09W	23.74S	5.99E
3527.00	.4	190.5	3526.79	.39S	.10W	24.13S	5.89E
3577.00	.2	176.5	3576.79	.35S	.03W	24.48S	5.86E
3627.00	.0	24.7	3626.79	.13S	.02W	24.61S	5.84E
3677.00	.3	12.5	3676.79	.13N	.08E	24.47S	5.91E
3727.00	.2	46.5	3726.79	.03N	.13E	24.44S	6.04E
3777.00	.2	95.6	3776.79	.02N	.15E	24.42S	6.20E
3827.00	.5	140.2	3826.79	.19S	.27E	24.62S	6.46E
3877.00	.8	151.0	3876.78	.42S	.39E	25.04S	6.85E
3927.00	.9	159.1	3926.78	.70S	.31E	25.74S	7.16E
3977.00	1.1	164.7	3976.77	.87S	.25E	26.61S	7.41E

MERISOL
W.D.W. #319

DEPTH	DEVIATION ANGLE	DEVIATION AZIMUTH	T.V.D.	DRIFT COORDINATES STATION N-S	STATION E-W	TOTAL N-S	TOTAL E-W
4027.00	1.1	160.4	4026.76	.82S	.24E	27.43S	7.65E
4077.00	1.0	161.1	4076.75	.89S	.27E	28.33S	7.92E
4127.00	.8	147.9	4126.74	.77S	.36E	29.10S	8.29E
4177.00	1.0	146.2	4176.74	.75S	.43E	29.84S	8.72E
4227.00	.9	138.5	4226.73	.66S	.51E	30.50S	9.23E
4277.00	1.0	125.6	4276.72	.54S	.65E	31.05S	9.88E
4327.00	1.0	117.9	4326.72	.43S	.73E	31.48S	10.60E
4377.00	.9	118.5	4376.71	.44S	.75E	31.92S	11.36E
4427.00	.7	101.5	4426.70	.26S	.65E	32.18S	12.00E
4477.00	.8	103.3	4476.70	.15S	.70E	32.32S	12.70E
4527.00	.7	116.4	4526.69	.12S	.62E	32.44S	13.32E
4577.00	.7	117.7	4576.69	.25S	.56E	32.69S	13.88E
4627.00	.6	134.3	4626.69	.32S	.46E	33.02S	14.34E
4677.00	.6	141.6	4676.68	.42S	.38E	33.44S	14.72E
4727.00	.7	159.0	4726.68	.49S	.26E	33.92S	14.99E
4777.00	.6	155.4	4776.68	.49S	.20E	34.42S	15.18E
4827.00	.6	166.8	4826.67	.52S	.18E	34.93S	15.36E
4877.00	.6	168.4	4876.67	.53S	.08E	35.46S	15.45E
4927.00	.7	180.9	4926.67	.56S	.02E	36.02S	15.46E
4977.00	.6	198.9	4976.67	.54S	.08W	36.56S	15.38E
5027.00	.5	210.7	5026.66	.45S	.23W	37.02S	15.15E
5077.00	.3	241.8	5076.66	.24S	.22W	37.26S	14.92E
5127.00	.0	329.5	5126.66	.04S	.15W	37.29S	14.77E
5177.00	.4	13.3	5176.66	.15N	.03E	37.14S	14.81E
5227.00	.7	36.8	5226.66	.38N	.20E	36.76S	15.01E
5277.00	.8	65.4	5276.66	.34N	.50E	36.42S	15.51E
5327.00	.8	66.4	5326.65	.27N	.67E	36.15S	16.18E
5377.00	.9	65.3	5376.64	.30N	.68E	35.85S	16.86E
5427.00	1.0	67.9	5426.64	.40N	.71E	35.46S	17.57E
5477.00	1.0	67.8	5476.63	.40N	.80E	35.05S	18.37E
5527.00	.9	74.2	5526.62	.31N	.91E	34.74S	19.28E
5577.00	.9	75.5	5576.61	.31N	.77E	34.43S	20.05E
5627.00	.8	81.1	5626.61	.08N	.72E	34.35S	20.77E
5677.00	.7	76.1	5676.60	.17N	.59E	34.19S	21.36E
5727.00	.8	86.4	5726.60	.10N	.67E	34.09S	22.03E
5777.00	.8	108.1	5776.60	.10S	.67E	34.19S	22.71E
5827.00	.6	109.5	5826.59	.16S	.55E	34.35S	23.25E
5877.00	.9	129.0	5876.59	.33S	.59E	34.68S	23.84E
5927.00	.6	144.1	5926.58	.44S	.45E	35.12S	24.29E
5977.00	.5	143.0	5976.58	.45S	.35E	35.57S	24.64E

MERISOL
W.D.W. #319

DEPTH	DEVIATION ANGLE	DEVIATION AZIMUTH	T.V.D.	DRIFT COORDINATES STATION N-S	STATION E-W	TOTAL N-S	TOTAL E-W
6027.00	.6	143.4	6026.58	.36S	.27E	35.95S	24.91E
6077.00	.6	125.5	6076.58	.31S	.34E	36.26S	25.25E
6127.00	.5	145.7	6126.57	.30S	.34E	36.55S	25.59E
6177.00	.5	166.8	6176.57	.39S	.19E	36.94S	25.78E
6227.00	.7	183.7	6226.57	.48S	.04E	37.42S	25.82E
6277.00	.6	193.8	6276.57	.54S	.09W	37.96S	25.74E
6327.00	.6	201.2	6326.56	.48S	.18W	38.44S	25.55E
6377.00	.4	221.3	6376.56	.35S	.27W	38.79S	25.28E
6427.00	.4	211.3	6426.56	.36S	.21W	39.14S	25.08E
6477.00	.3	203.1	6476.56	.28S	.12W	39.42S	24.96E
6527.00	.2	136.2	6526.56	.22S	.01E	39.64S	24.96E
6577.00	.5	121.2	6576.56	.13S	.30E	39.77S	25.27E
6627.00	.3	37.8	6626.56	.04N	.29E	39.73S	25.56E
6677.00	.2	79.3	6676.55	.18N	.25E	39.56S	25.81E
6727.00	.5	49.3	6726.55	.16N	.18E	39.40S	25.99E
6777.00	.4	2.4	6776.55	.50N	.17E	38.90S	26.16E
6827.00	.4	39.2	6826.55	.35N	.14E	38.54S	26.30E
6877.00	.8	334.4	6876.55	.38N	.04E	38.17S	26.34E
6927.00	.4	313.1	6926.55	.41N	.23W	37.76S	26.11E
6977.00	.5	312.0	6976.54	.26N	.20W	37.49S	25.91E
7027.00	.6	316.6	7026.54	.33N	.45W	37.16S	25.46E
7077.00	.9	335.0	7076.54	.52N	.31W	36.65S	25.15E
7127.00	1.7	341.1	7126.53	1.00N	.38W	35.65S	24.77E
7177.00	2.1	330.4	7176.50	1.53N	.78W	34.12S	23.99E
7227.00	2.0	325.9	7226.46	1.50N	1.07W	32.62S	22.92E
7277.00	2.1	318.8	7276.43	1.32N	1.07W	31.30S	21.85E
7327.00	1.9	310.6	7326.40	1.19N	1.23W	30.11S	20.62E
7373.00	1.4	307.7	7372.38	.92N	1.09W	29.18S	19.54E

THE FIRST POINT INFORMATION:							
27.00	.2	333.5	27.00	.00N	.00E	.00N	.00E
THE LAST POINT INFORMATION:							
7373.00	1.4	307.7	7372.38	.92N	1.09W	29.18S	19.54E

FINAL EAST-WEST DRIFT = 19.54 E
FINAL NORTH-SOUTH DRIFT = 29.18 S
FINAL DRIFT DISTANCE = 35.12 FT
FINAL DRIFT DIRECTION = S 33.80 E

BAKER HUGHES

Baker Atlas

COMPANY	MERSISOL		FILE NO: 20104
WELL	W.D.W. #319		API NO: 42-201-N/A
FIELD	WASTE DISPOSAL WELL		
COUNTY	HARRIS	STATE TEXAS	

LOCATION:
4140' FNL & 17,145' FEL OF THE
RICHARD & ROBERT VINCE SURVEY, (A-76)

ELEVATIONS:
KB 19.5 FT
DF 18.5 FT
GL N/A

FINAL PRINT

DATE 12-AUG-2000

APPENDIX 5-4
INJECTION WELL TUBULAR STRESS CALCULATIONS

INJECTION WELL NO. 1 (WDW147)

APPENDIX 5-4
INJECTION WELL TUBULAR STRESS CALCULATIONS

INJECTION WELL NO. 1 (WDW147)

A. **Burst:** The greatest rupture stresses induced over the life of the injection tubing occur during injection operations. This scenario assumes that the maximum injection pressure is realized while injecting waste fluids at the maximum permitted specific gravity. The annular fluid is uses as a back-up.

$$P_{maxwc} = 0.433 \times SG_{max} \times D + P_{maxinj}$$

Where:

P_{maxwc} = maximum pressure at worst case conditions (psi)

0.433 = Pressure Gradient (psi/ft for use with SG data)

SG_{max} = maximum specific gravity of injection fluid (used 1.3)

D = depth of tubing (feet)

P_{maxinj} = maximum injection pressure

$$P_{maxwc} = 0.433 \times 1.3 \times 6{,}481 + 1{,}200$$

$$P_{maxwc} = 4{,}848\ psi$$

Safety Factor = 7,780/4,898 = 1.625

B. **Collapse:** The maximum loading condition for collapse of the injection tubing is governed by conditions present during annular pressure testing of the well. This scenario assumes that the waste fluid inside the tubing is at it minimum specific gravity.

$$P_{maxwc} = 0.052 \times \rho \times D + P_{maxan}$$

Where:

P_{maxwc} = maximum pressure at worst case conditions (psi)

0.052 = Pressure Gradient (psi/ft *where* r = lb/gal)

ρ = density of annular fluid (lb/gal)

D = depth of tubing (feet)

P_{maxan} = maximum annular pressure

$$P_{maxwc} = 0.052 \times 10.0 \times 6{,}481 + 1{,}200$$

$$P_{maxwc} = 4{,}536\ psi$$

Safety Factor = 6,350/4,536 = 1.40

C. **Tension:** The tensile strength of the injection tubing is governed by the unit tubular weight, with effects from buoyancy neglected. The worst case scenario assumes that the tubing is also filled with injection fluid with a void tubing-casing annulus.

$$W_{maxwc} = \left[W_p \times D\right] + [8.33 \times SG_{max} \times V \times D]$$

Where:

W_{maxwc} = maximum tensile weight at worst case conditions (lbs)

W_p = weight of tubing in air (lb/ft)

8.33 = conversion factor (SG to lb/gal)

SG_{max} = maximum specific gravity of injection fluid (used 1.3)

V = volume per unit length inside tubing (gal/lin ft)

D = depth of tubing (feet)

$$W_{max} = [11.6 \times 6{,}481] + [8.33 \times 1.3 \times 0.6528 \times 6{,}481]$$

$$W_{max} = 120{,}994\ lbs$$

Safety Factor = 212,000/120,994 = 1.75

This demonstration need not be performed for surface and protective casing because the maximum stresses are induced during cementing of the casing strings. Since this well has been completed with no problems, the casings will be strong enough to endure the maximum burst and collapse pressure and axial loading for the design life of the well.

INJECTION WELL NO. 2 (WDW319)

APPENDIX 5-4
INJECTION WELL TUBULAR STRESS CALCULATIONS

INJECTION WELL NO. 2 (WDW319)

D. **Burst:** The greatest rupture stresses induced over the life of the injection tubing occur during injection operations. This scenario assumes that the maximum injection pressure is realized while injecting waste fluids at the maximum permitted specific gravity. The annular fluid is uses as a back-up.

$$P_{maxwc} = 0.433 \times SG_{max} \times D + P_{maxinj}$$

Where:

P_{maxwc} = maximum pressure at worst case conditions (psi)

0.433 = Pressure Gradient (psi/ft for use with SG data)

SG_{max} = maximum specific gravity of injection fluid (used 1.3)

D = depth of tubing (feet)

P_{maxinj} = maximum injection pressure

$$P_{maxwc} = 0.433 \times 1.3 \times 6{,}498 + 1{,}200$$

$$P_{maxwc} = 4{,}858\, psi$$

Safety Factor = 9,960/4,858 = 2.05

E. **Collapse:** The maximum loading condition for collapse of the injection tubing is governed by conditions present during annular pressure testing of the well. This scenario assumes that the waste fluid inside the tubing is at it minimum specific gravity.

$$P_{maxwc} = 0.052 \times \rho \times D + P_{maxan}$$

Where:

P_{maxwc} = maximum pressure at worst case conditions (psi)

0.052 = Pressure Gradient (psi/ft *where* r = lb/gal)

ρ = density of annular fluid (lb/gal)

D = depth of tubing (feet)

P_{maxan} = maximum annular pressure

$$P_{maxwc} = 0.052 \times 10.0 \times 6{,}498 + 1{,}200$$

$$P_{maxwc} = 4{,}579\ psi$$

Safety Factor = 6,230/4,579 = 1.36

F. **Tension:** The tensile strength of the injection tubing is governed by the unit tubular weight, with effects from buoyancy neglected. The worst-case scenario assumes that the tubing is also filled with injection fluid with a void tubing-casing annulus.

$$W_{maxwc} = [W_p \times D] + [8.33 \times SG_{max} \times V \times D]$$

Where:

W_{maxwc} = maximum tensile weight at worst case conditions (lbs)

W_p = weight of tubing in air (lb/ft)

8.33 = conversion factor (SG to lb/gal)

SG_{max} = maximum specific gravity of injection fluid (used 1.3)

V = volume per unit length inside tubing (gal/lin ft)

D = depth of tubing (feet)

$$W_{max} = [26 \times 6{,}498] + [8.33 \times 1.3 \times 1.607 \times 6{,}498]$$

$$W_{max} = 282{,}028\ lbs$$

Safety Factor = 693,000/282,028 =2.46

This demonstration need not be performed for surface and protective casing because the maximum stresses are induced during cementing of the casing strings. Since this well has been completed with no problems, the casings will be strong enough to endure the maximum burst and collapse pressure and axial loading for the design life of the well.